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IMPACT OF WETTABILITY ALTERATION ON RELATIVE PERMEABILITY IN SANDSTONE FOR GAS-CONDENSATE APPLICATION

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ABSTRACT

Gas condensate reservoirs can experience severe production losses once the bottom-hole flowing pressure drops below the dew point pressure, where condensate starts to form near the wellbore. During production under these conditions, liquid hydrocarbons start to accumulate forming a condensate bank near the wellbore which adheres to the surface of the rock and reduces or completely blocks the mobility of the gas. In addition to condensate, water accumulation could gather near the wellbore and negatively affect the relative permeability of gas in that region. A novel approach to overcome this condensate banking and water damage behavior is by altering the wettability of the rock from liquid-wet to gas-wet or intermediate-gas-wet using chemical treatment.

The aim of this study is to experimentally examine the effectiveness of the chemical treatment to optimize the wettability and enhance gas relative permeability to increase the gas well productivity. The experiments were conducted on Grey Berea sandstone core samples with length ranging between 1 and 6 inches. The average porosity and permeability of the rock samples used in the treatment were 20% and 100 mD, respectively.

Different weight percentages of the surfactant were mixed with different combinations of solvents and were injected into the core sample then aged at a temperature of 180^{o} F. After that, the sample was tested for spontaneous decane imbibtion, contact angle, and gas relative permeability to figure out the optimum combination and optimum weight percentage that altered the rock wettability. We were able to correlate the enhancement in relative permeability characteristics with the

observed variation in spontaneous imbibition plots. This is a new and important contribution to the literature in the field.

1. INTRODUCTION

1.1 Overview

The Oil and Gas industry is progressing vastly to meet the energy demand using the best innovative technology available. Throughout the years, many advanced technologies have been invented and developed to produce oil and gas efficiently to keep both cost and environmental impact as low as possible. Some of these early inventions that added a lot to the industry include horizontal drilling in 1929 (Helms, 2008) and hydraulic fracturing in 1947 (Montgomery & Smith, 2010). The industry is investing more effort to develop more technologies and solutions to enhance oil and gas production. One common topic in discussion these days among operators of gas-condensate wells is wettability alteration which, if successfully developed and optimized, could revive many shut-in gas wells.

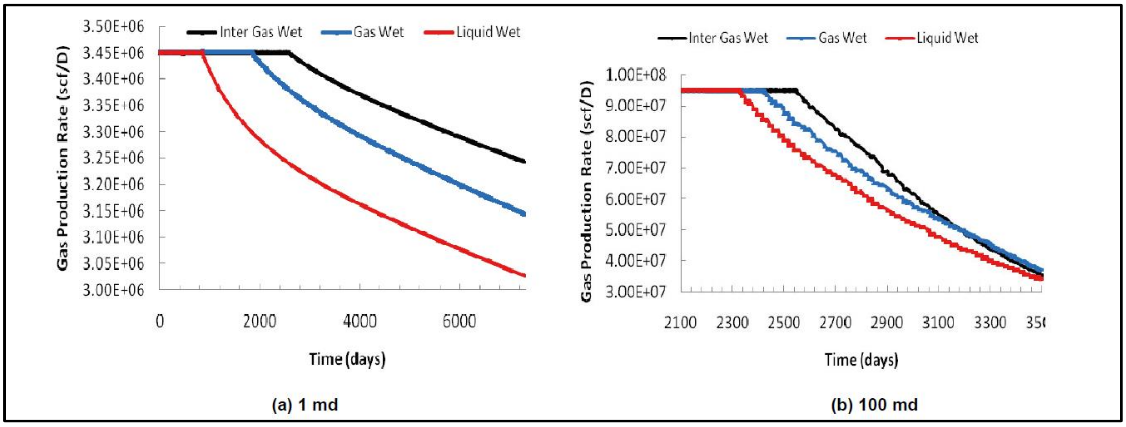
1.2 Problem Statement

Gas reservoirs' productivity decreases with the forming of condensate banking as the bottom-hole pressure drops below the dew point pressure and as water accumulates near the wellbore due to drilling and other workover operations. Other possible sources for this water might be an adjacent water aquifer. This liquid accumulation near the wellbore significantly impacts the gas production as the gas relative permeability could be reduced by more than 95% (Bang et al., 2009). In many cases, condensate blockage stops the deliverability of the well completely (Abdallah et al., 2007).

Advanced technologies are used to delay the condensation of liquid hydrocarbons near the wellbore such as hydraulic fracturing and horizontal completion (Al-Anazi et al., 2007).

A promising approach is to perpetually alter the wettability near the well from liquid-wet to intermediate-gas-wet or gas-wet in order to uplift the gas production of the wells. There are several undergoing studies to identify the optimum chemical treatment that gives the most permeant enhancement to the gas relative permeability and ultimately to the gas production.

Zoghbi et al. (2010) used a simulation model and found that changing the wettability to intermediate gas-wet will provide the best deliverability for the gas wells independent of the permeability as shown in **Fig. 1.**; although the effect is more pronounced in low permeability formations.



(a) 1 md

(b) 100 md

Figure 1. Gas productivity based on three wettability scenarios (Zoghbi et al, 2010)

Although this was one of very few studies that discussed an optimization approach, they had no experimental evidence for the relative permeability graphs they used in their simulations. In this study, a chemical surfactant is mixed with two different solvents at certain weight percentages and heated at temperature up to 180^o F (~ 83^o C). This mixture is used to alter the wettability of Grey Berea core samples from liquid-wet to intermediate-gas-wet or preferentially gas-wet.

The effectiveness of the treatments is evaluated using several methods including spontaneous decane imbibition, contact angle, and 2-phase relative permeability. These methods are discussed thoroughly in the **methodology** chapter.

2. LITERATURE REVIEW

2.1 Deliverability Reduction due to Liquid Blocking

In gas reservoirs, pressure will continue to drop with production in a process called depletion. There are several types of gas reservoirs characterized based upon compositions, pressure, and temperature (phase diagram). Some of these reservoirs will encourage liquid hydrocarbons to form near wellbore with decreasing pressure as production progresses, these are called gas-condensate reservoirs. **Fig. 2** demonstrates that condensate will start to form as pressure declines based on the composition of the fluid.

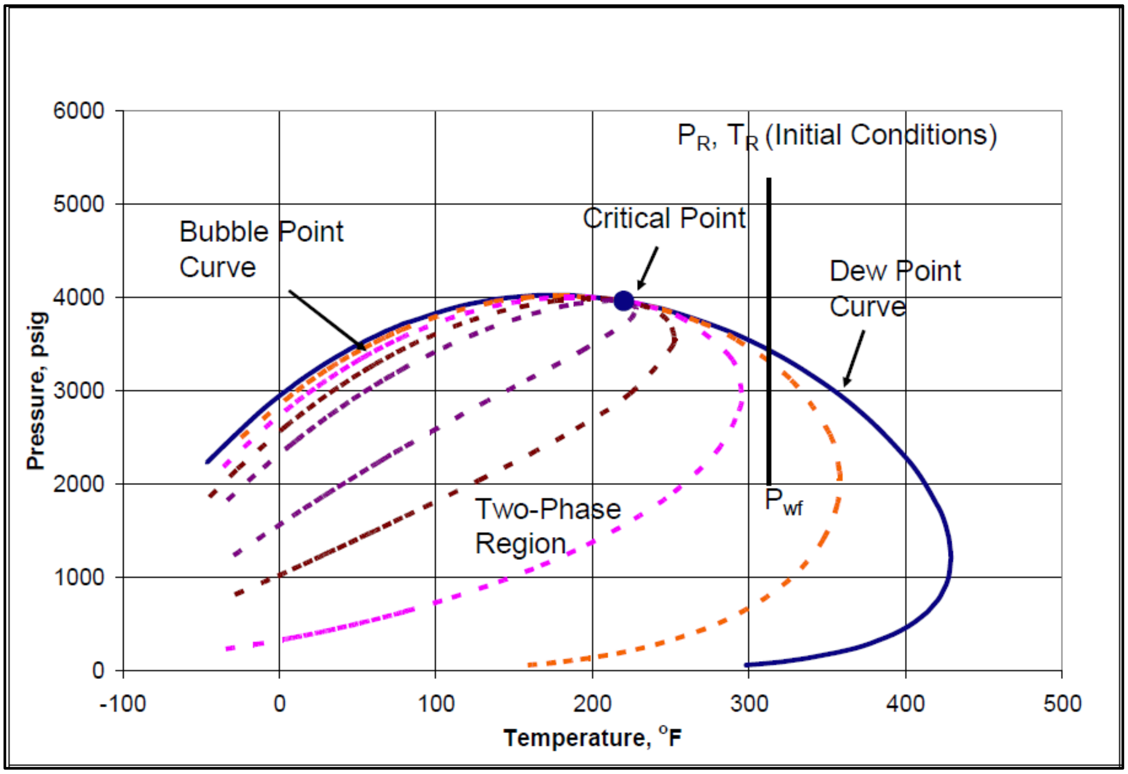


Figure 2. Condensate formation with pressure depletion (Bang, 2007)

Bang (2007) illustrated that once condensate is formed, condensate will be trapped due to the capillary pressure and will adhere to the rock due to the low liquid mobility. Water is an additional issue that accumulates near wellbore area from many sources such as drilling fluids. Both liquids will accumulate near wellbore and cause significant reduction in gas production.

Gas deliverability from condensate reservoirs was studied as early as 1963. A tight formation producing a rich condensate gas in the Knox Bromide field, in Oklahoma was studied. The performance of both reservoir and flowing bottom hole pressures were evaluated at a constant flowing gas rate of 40 MMcf/D with condensate production. **Fig. 3** shows that condensate has a significant impact at flowing bottom hole pressure more than formation (reservoir) pressure due to condensate blockage near the wellbore (Hurst et al., 1963).

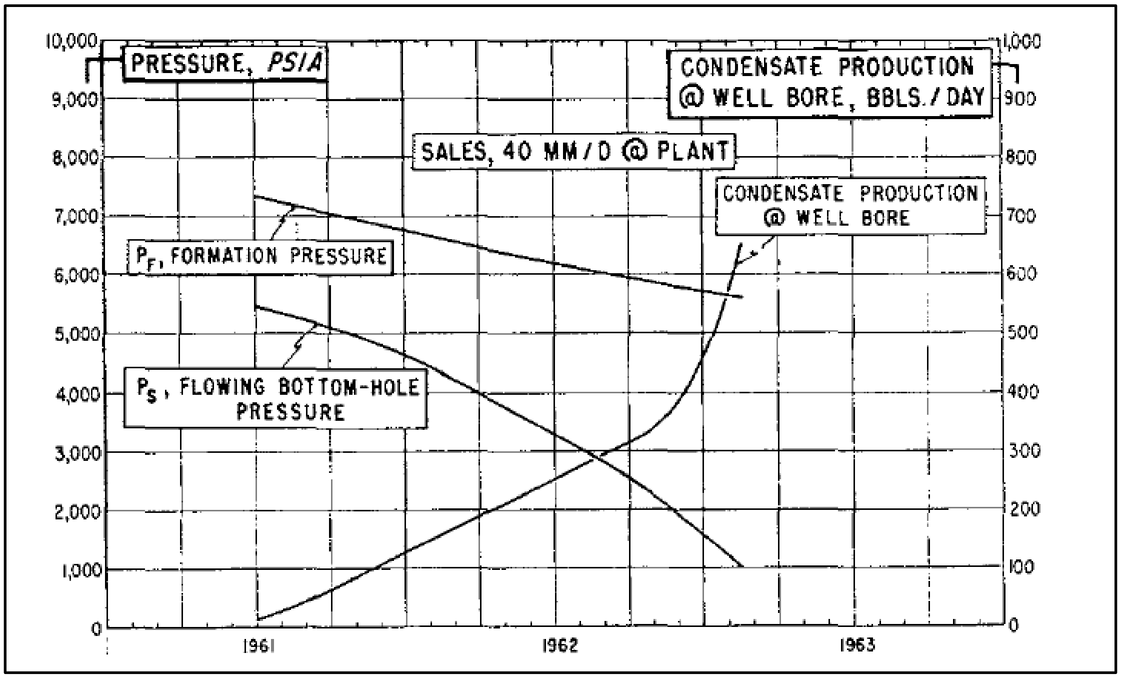


Figure 3. Impact of condensate on flowing bottom-hole pressure (Hurst et al., 1963)

The poor recovery of the rich gas of approximately 10% in Cal Canal field, in California is directly related to the retrograde dropout and high water saturation of 59%. Authors suggested several completion solutions, such as tubing size selection shown in **Fig. 4** and artificial lift solutions, to mitigate the severe liquid loading problems (Engineer, 1985).

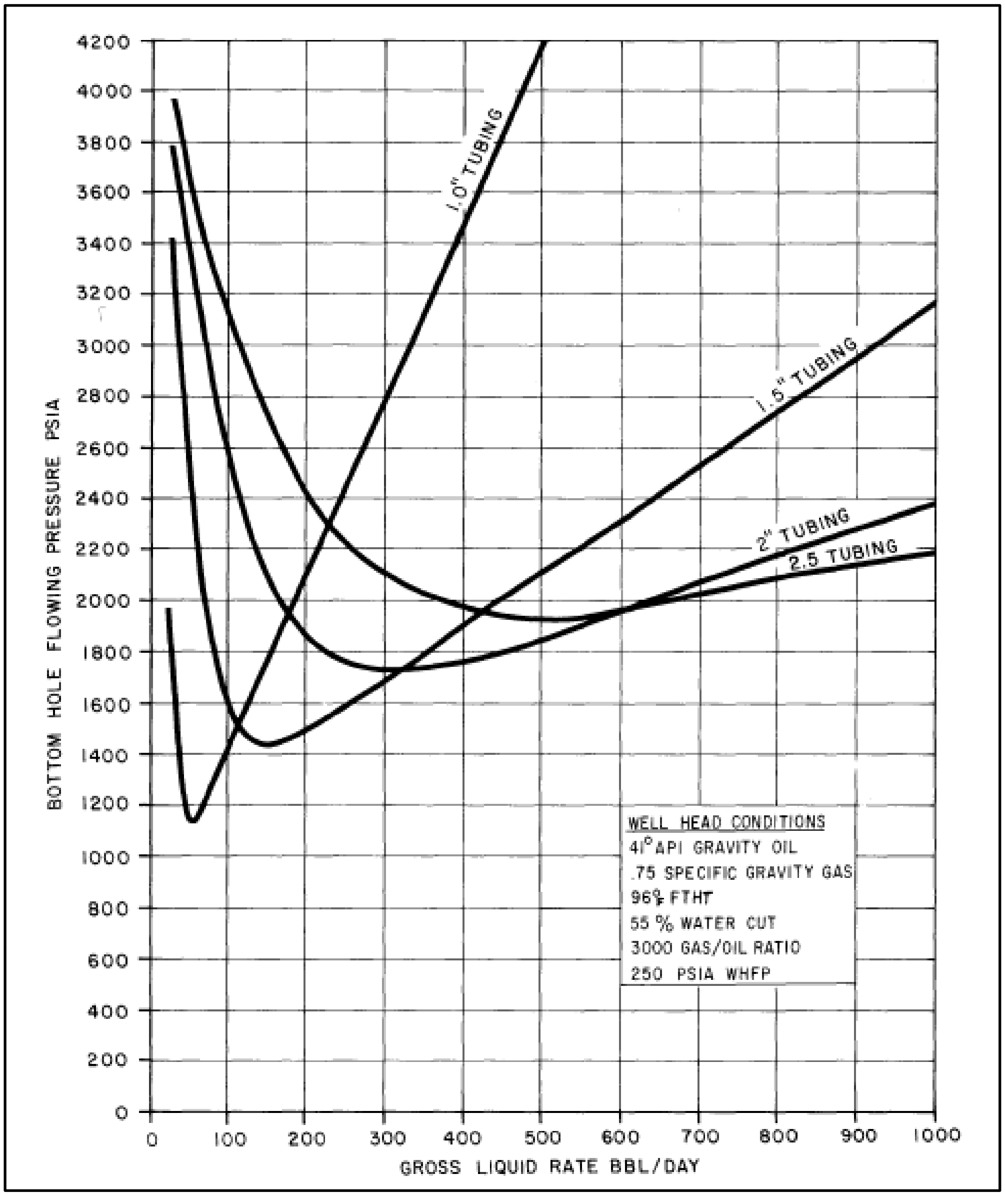


Figure 4. Mitigating liquid loading with different tubing sizes (Engineer, 1985)

A simulation study that showed several radial liquid profiles based on different flowing bottom hole pressures from both lean and rich gas reservoirs have been investigated. The study concluded that production can be optimized based on selecting the suitable flowing bottom hole pressure taking the phase diagram of the fluids into consideration. A study of one year simulation of the pressure profile based on different flowing bottom hole pressures was investigated. It showed clearly that the higher the flowing bottom hole pressure, the less it is affected by the pressure drop as shown in **Fig. 5**. One output of this study that revealed a negligible effect of lean gas contradicted what had been experienced at the Arun field in 1994 (Cvetkovic et al., 1990).

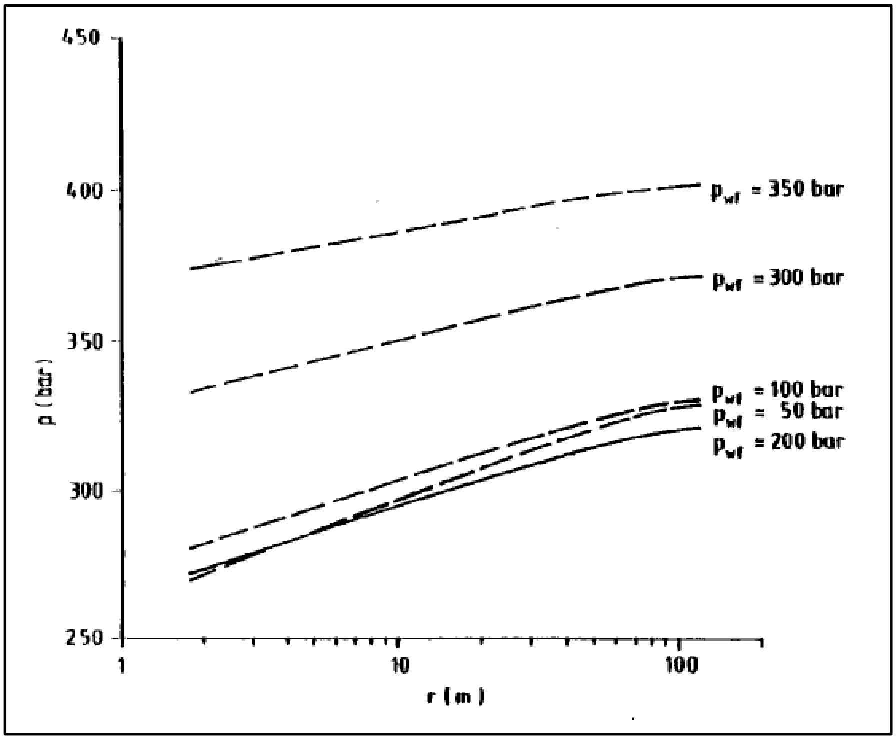


Figure 5. Effect of both bottom-hole pressure and distance on pressure drop (Cvetkovic et al., 1990)

Afidick et al. (1994) used a compositional model in a radial-single well and found that liquid accumulation reduces the gas deliverability of a single well in Arun field by half. This significant decline in gas production occurred even though the experimental PVT analysis showed that the gas is lean with maximum liquid dropout of about 1.1% of total volume in **Fig. 6**. This clarifies that with more rich gas, the liquid blockage around wellbore reduces gas production even by more than 50%. Authors also found that liquid accumulation will occur in high kh zones more than low kh zones and that liquid will not convert back to vapor if the well is shut-in.

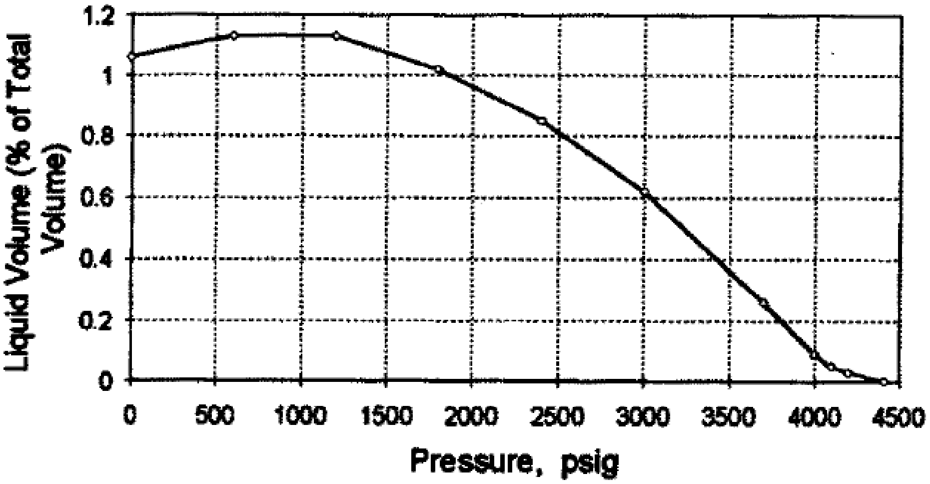


Figure 6. PVT analysis of the maximum liquid dropout (Afidick et al., 1994)

2.2 Relative Permeability

Fussell (1973) pioneered the effort and considered the effect of relative permeability on the modified one-dimensional radial model used to predict the long-term performance of a single well. The prediction showed that presence of condensate reduced the deliverability of the well by a factor of three. The study also showed the significance of relative permeability by comparing three different cases of condensate displacement efficiency by gas (**Fig. 7**).

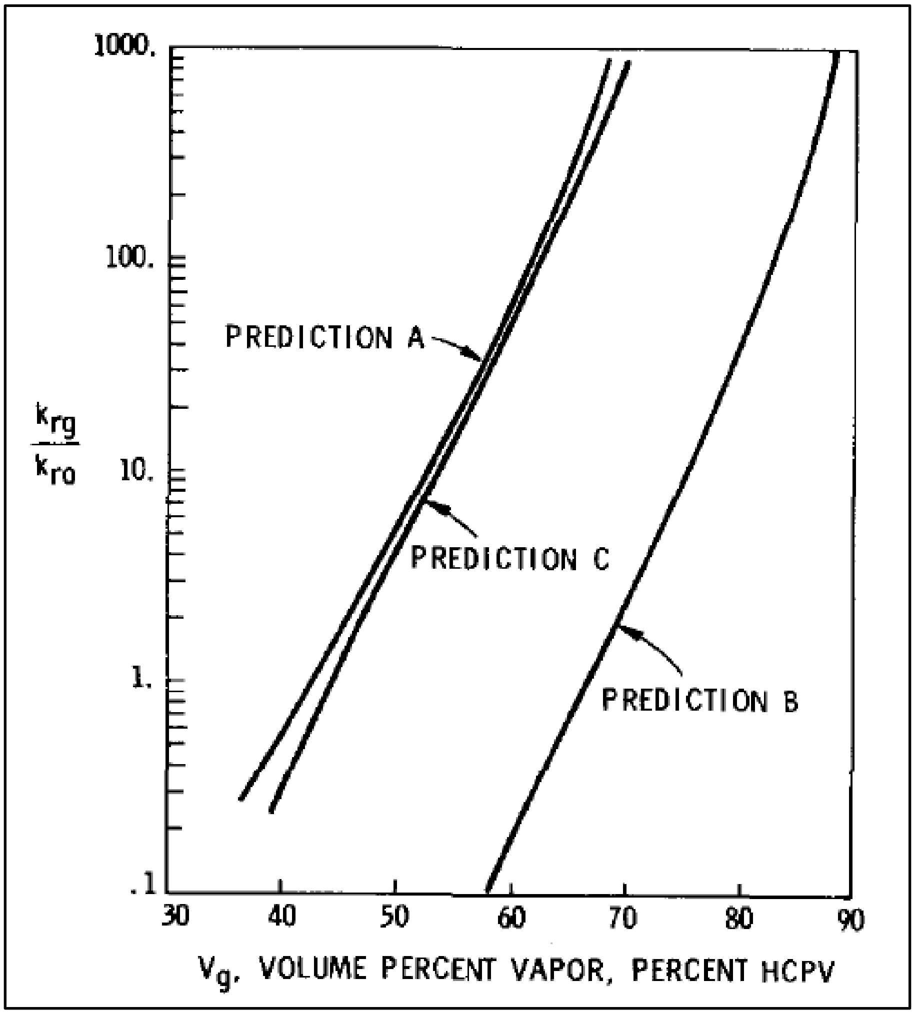


Figure 7. Different cases of condensate displacement efficiency by gas (Fussell, 1973)

Another compositional one-dimensional radial model study revealed that relative permeability is the most sensitive factor that affects the productivity of the gas-condensate well. This study concluded that production loss happens in few days or even hours once bottom-hole pressure drops below the dew point pressure. This model was not really representing the actual reservoir since the connate water saturation was factored out (Hinchman & Barree, 1985).

Hydrocarbon mixtures with properties identical to the reservoir gas-condensate fluids were prepared. Also, actual carbonate samples from a gas-condensate reservoir in Abu Dhabi were used to simulate the field flow conditions under reservoir pressure and temperature. Authors concluded that in the presence of the immobile liquid and under reservoir conditions, the gas relative permeability declined more with increasing condensate saturation compared to experiments under ambient conditions (Gravier et al., 1986).

Accounting for the presence of the connate water, gas and oil relative permeability was investigated using a 5.5 ft long, high permeability (1.4 darcy) Clashach sandstone core. Fishlock & Smith (1993) found that forming the condensate with the existence of 19% connate water reduces the gas relative permeability by 60%. They investigated the multi-phase flow in the gas-condensate system with different connate water saturations under both pressure depressurizing and waterflooding system to mimic the actual reservoir behavior. Authors found that if mobile water is existing, there is possibility to increase the gas relative permeability for a particular gas saturation.

2.3 Proposed Studies for Treating Liquid Blocking

To improve the relative permeability curve and ultimately enhance the gas productivity, many methods to either maintain the flowing bottom-hole pressure above the dew-point pressure or by modifying the phase behavior of the condensate fluid were proposed (Bang, 2007).

2.3.1 Pressure Maintenance

Back to 1970, a two-dimensional model was initiated to predict the performance of the Carson Creek field in Alberta after gas cycling. This study showed that during partial cycling, where 52% of the lean gas is injected back to the reservoir for a certain period of time, the process resulted to a higher recovery of the liquids (Abel et al., 1970).

Luo et al. (2001) investigation of condensate recovery using both partial and full pressure maintenance that were done in the lab using waxy condensate, found that lean gas will re-evaporate some of the heavy hydrocarbons (C_{20}^{+}) in addition to the intermediate hydrocarbons. The authors concluded that the mass transfer between the injected lean gas and the original condensate will increase the dew point pressure leading to an early condensation process.

Focusing on the optimum time and volume of gas to be injected in order to permanently remove the condensate bank around the wellbore, a one-time study was conducted by Marokane et al. (2002). Three condensate samples were used having maximum liquid dropout as 6%, 11% and 21%. Consulting reservoir simulation results, they found that the best time to start injecting to the lean gas condensate reservoir is when the average reservoir pressure dropped below the maximum liquid dropout pressure. On the other hand, to achieve more recovery in rich gas condensate, the gas injection into the reservoir should be done at an average reservoir pressure higher than the maximum liquid dropout pressure. Also, authors found a small increase of 1.3% in the recoverable gas for both lean and rich gas in determining the optimum injected volume. This was done by increasing the injected gas volume from 6% to 16%, yet, the small increase might be valuable considering the total economic analysis of the project.

Al-Anazi et al. (2004) assessed the success of the methane capability to revaporate the condensate from the tested cores to enhance the gas productivity of the well. Authors found that the methane did not only revaporate the condensate but it restored the original permeability of the cores. The downside of this method as pronounced by authors is that it required a lot of time to accomplish (100s of PV). They also discussed that one way to speed up the revaporization process of the condensate is by increasing the methane pressure and flow rate.

2.3.2 Phase Behavior

Takeda et al. (1997) developed a two-phase compositional simulator to study the behavior of the gas-condensate reservoir. Using a two-dimensional radial geometry, authors found that if permeability around the wellbore vicinity is low, pressure decreased quickly and condensate dropouts became higher.

Real reservoir fluid was used to conduct a constant composition expansion experiment to simulate the condensate deposition under high pressure high temperature conditions (HPHT). They evaluated the effect on the phase behavior of the reservoir fluid by the injection carbon dioxide and propane and concluded that propane seems practical in certain conditions to reduce the damage due to condensate blocking (Jamaluddin et al., 2001).

Both pressure maintenance and phase behavior alteration did not permanently prevent liquid blockage around the wellbore area which encouraged the industry to seek other alternatives to increase the productivity of the gas wells.

2.4 Wettability

Wettability can be described based on the strength of the interfacial forces between the solids and liquid. A fluid is referred as a “wetting” fluid if it spreads over the solid surface and forms 180-degree contact angle because of strong interfacial forces. On the other hand, a “non-wetting” fluid that has weak surface tension with the solids shrinks up and forms almost zero-degree contact angle as shown in **Fig. 8** (Abdallah et al., 2007).

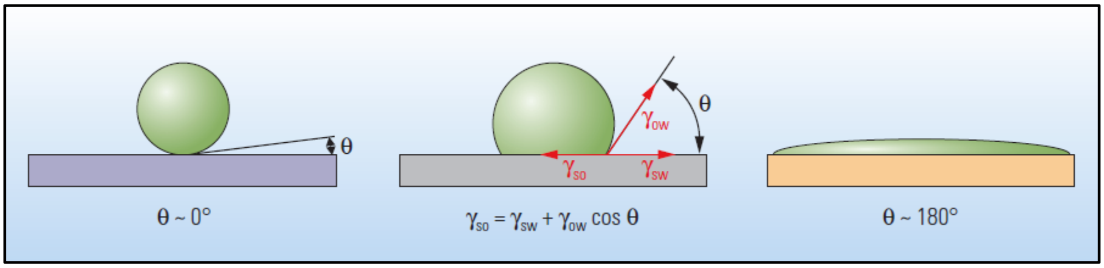


Figure 8. Contact angle of different wetting phases (Abdallah et al., 2007)

Anderson (1986) did several studies on wettability alteration using silica, oil and brine systems. He concluded that wettability alteration is occurring by both the adsorption of polar compounds and the deposition of the organic matter or by either of them.

There are different ways available to measure the wettability. Spontaneous imbibition is one method that is used in the lab to determine the preferential wettability of the rock sample using either deionized (DI) water or normal decane to represent oil (Abdallah et al., 2007).

2.4.1 Spontaneous Imbibition

Spontaneous imbibition is defined as the method of displacing a non-wetting fluid with a wetting fluid using the capillary pressure phenomena within the porous media (Zhang et al., 2014).

Amott (1959) conducted different experiments to examine the wettability of the rocks using water-oil system. Four displacements were done, two were spontaneous imbibition while the other two were forced displacements by one liquid to move the other. Wettability indices were calculated based on the ratio of the spontaneous imbibition volume to the total volume displaced for each experiment. The author revealed that “strong water-wet” cores displaced by water and oil have wettability indices close to one and zero, respectively. It was reported that “strong oil-wet” cores tend to have wettability indices approaching one when the cores are displaced with oil and zero with water displacement. Wettability indices of zero were noted for both water and oil displacements for “neutral wet” cores.

2.4.2 Using Chemical Surfactant to Alter Wettability

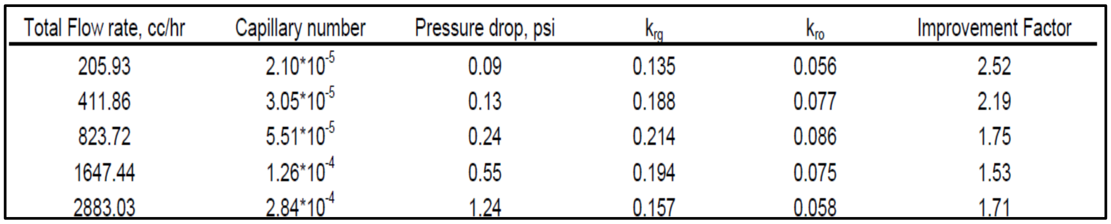
Recently, the industry is dedicating both time and effort to find the best surfactant that will perpetually alter the wettability of a specific type of the reservoir rocks to be intermediate-gas-wet.

Laboratory experiments were conducted to alter the wettability of both Berea and Chalk using two surfactants, FC754 and FC722. Contact angle results in the glass capillary tube showed that FC722 had more promising success than FC754, yet more expensive, by altering θ from 50° to 120° for the water-air system and from 0° to 60° for the normal decane-air system. Also, spontaneous imbibition tests showed that FC722 has decreased the water imbibition of Berea from 60% to around zero. Relative permeability tests indicated an increase in both gas and oil relative permeability from 0.54 to 0.89 at an oil saturation of 16.2% and from 0.025 to 0.03 at an oil saturation of 27.1%, respectively (Li & Firoozabadi, 2000).

Kumar et al. (2006) assessed the effectiveness of several surfactants using either methanol or a combination of methanol-water as a solvent. Using 2% of each of the different surfactants in the solvent, authors treated both outcrop Berea sandstone and reservoir sandstone core plugs that were taken from the North Sea. Under reservoir conditions, "Novec FC 4430" in a methanol-water solvent presented the highest enhancement in the relative permeability compared to other surfactants tested. This enhancement in the steady state relative permeability was found to be higher by a factor of 2 to 3 for the temperature ranging from 145 to 275° F.

Bang et al. (2008) developed a chemical treatment that alters the wettability of proppants to neutral-wet and reduces the liquid blockage of hydraulic fracturing. A surfactant mixed in a glycol-alcohol solvent under reservoir conditions i.e. pressure and temperature, had the capability to increase both gas and condensate relative permeabilities that were measured in the treated propped fractures by a factor up to 2.5 as shown in **Table 1**. Authors proposed based on their numerical simulation model shown in **Fig. 9** and **Fig. 10** that there is a chance for even small volumes of the chemical treatment to improve the fracture conductivity.

Table 1. Improvement factor of treated propped fractures (Bang et al., 2008)



Total Flow rate, cc/hr	Capillary number	Pressure drop, psi	k_{rg}	k_{ro}	Improvement Factor
205.93	$2.10*10^{-5}$	0.09	0.135	0.056	2.52
411.86	$3.05*10^{-5}$	0.13	0.188	0.077	2.19
823.72	$5.51*10^{-5}$	0.24	0.214	0.086	1.75
1647.44	$1.26*10^{-4}$	0.55	0.194	0.075	1.53
2883.03	$2.84*10^{-4}$	1.24	0.157	0.058	1.71

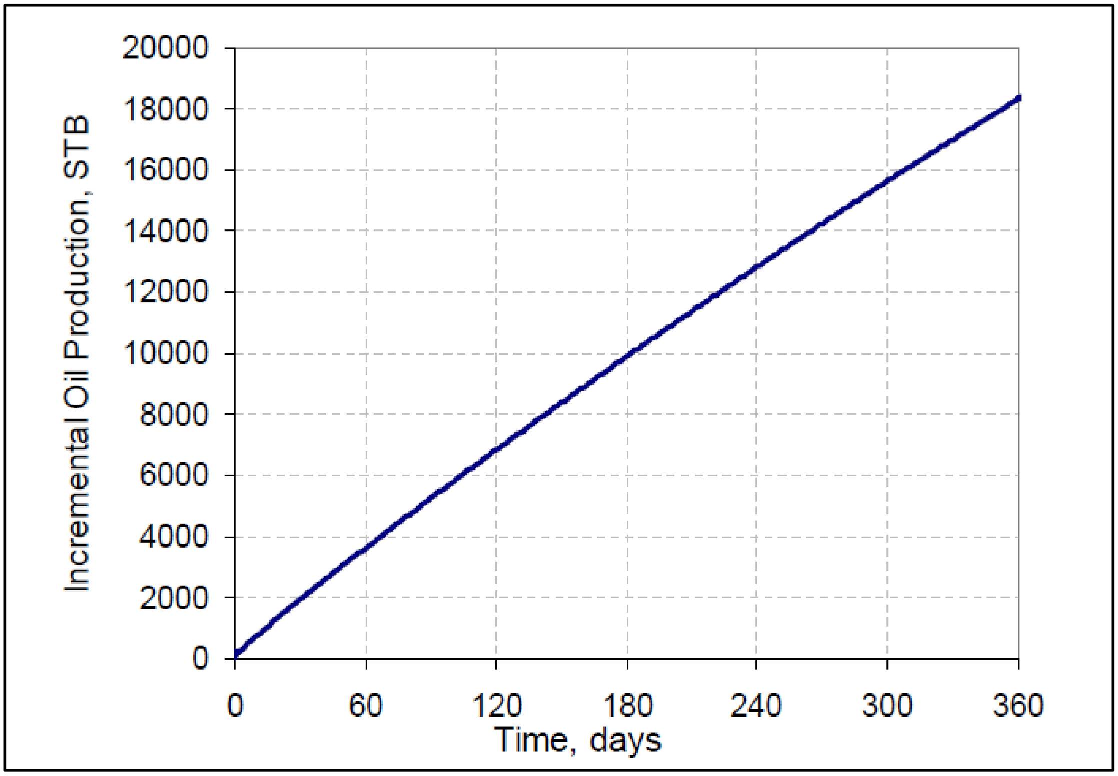


Figure 9. Improvement of chemical treatment on the oil production (Bang et al., 2008)

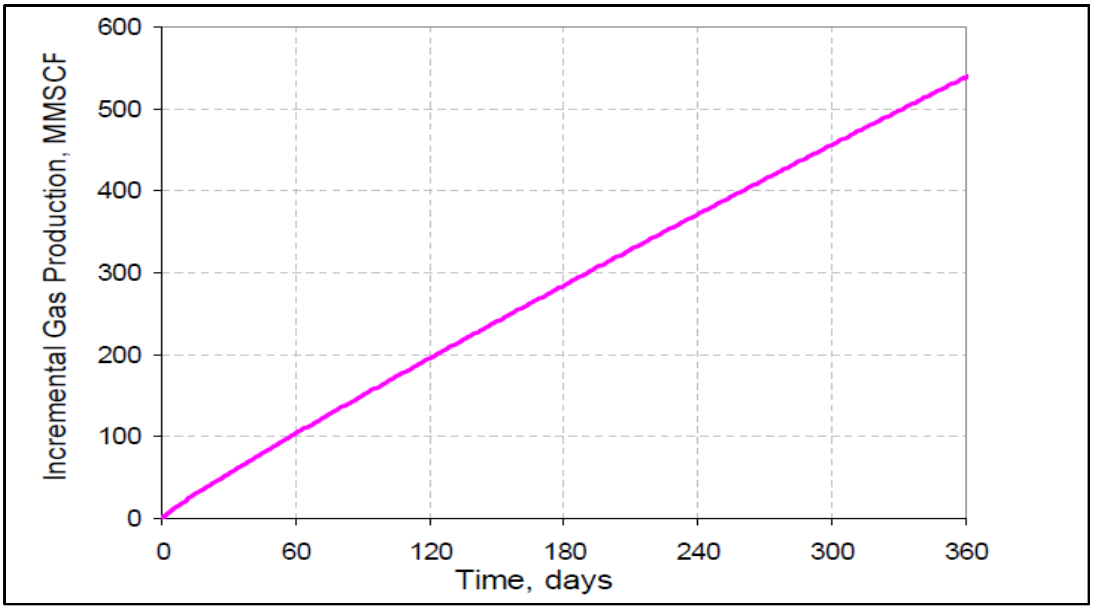


Figure 10. Improvement of chemical treatment on the gas production (Bang et al., 2008)

Zoghbi et al. (2010) using a CMG compositional simulation model, studied the effect on the gas-condensate well's deliverability based on several wettability ranging from being liquid-wet to gas-wet. Authors went further and investigated several factors that might affect the well productivity by the wettability alteration. Factors that were studied are reservoir permeability, reservoir pressure, and the treatment radius. Three wetting relative permeability states have been produced with 50%, 30% and 10% irreducible liquid saturation and 0.3, 0.5 and 0.2 gas end-point using Corey's correlations to represent liquid, intermediate, and gas wet, respectively. Initially, 15 ft radius around the wellbore was assumed to be treated by the chemical and its wettability is altered. Authors found that intermediate gas-wetting gives the significant enhancements to the gas-condensate well and it is more noticeable in the low permeability reservoirs as shown in **Fig. 11** and **Fig. 12**. Both reservoir pressure and treatment radius do not imply pronounced effect on the well productivity.

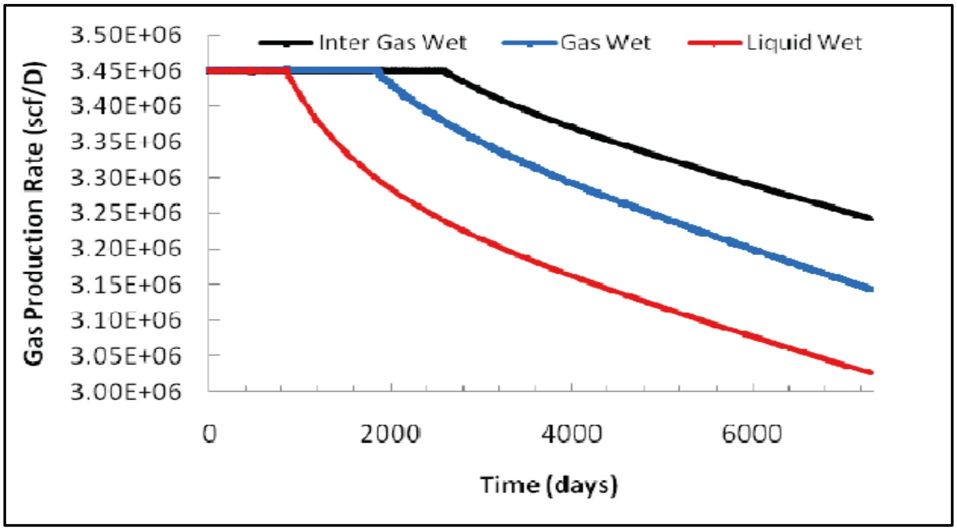


Figure 11. Gas productivity based on three wettability scenarios for 1 mD (Zoghbi et al, 2010)

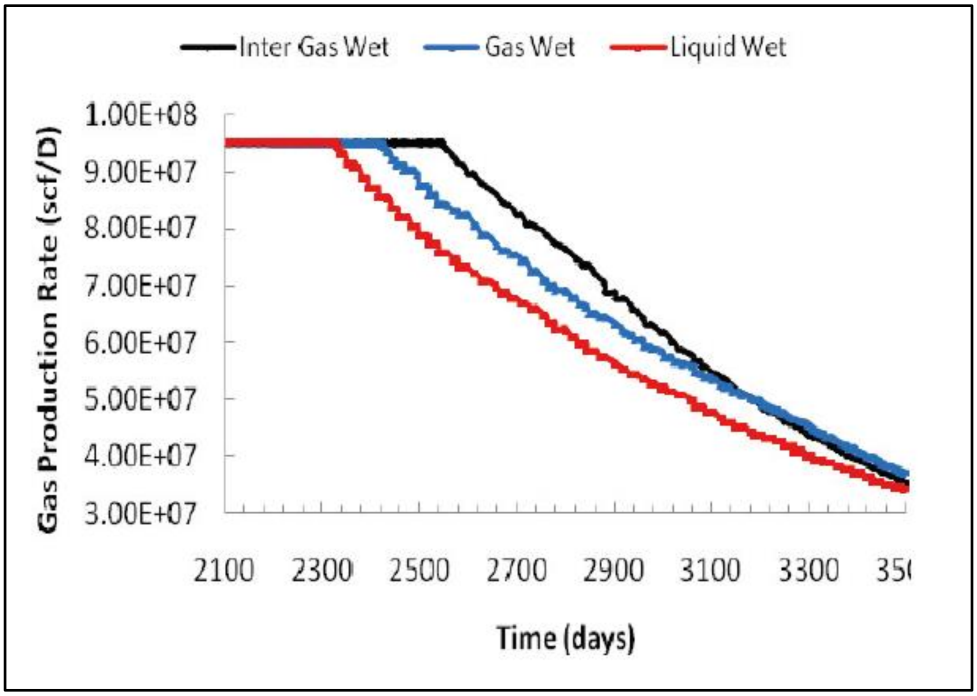


Figure 12. Gas productivity based on three wettability scenarios for 100 mD (Zoghbi et al, 2010)

2.4.2.1 Firing Berea

During the wettability alteration experiments, several authors found that Berea is sensitive to fresh water and salt which both encourage clay swelling and reduce permeability. To avoid clay swelling during the core initial saturation with either fresh water or brine, Berea is indorsed to be fired at a temperature higher than 500^o C (Wu & Firoozabadi, 2011).

Ma & Morrow (1994) did not recommend firing since it usually generates more permeability, porosity, and bulk volume than Berea cores have. Also, firing can cause cracking to the core due to thermal stresses.

2.4.2.2 Chemical Treatment

Several surfactants were used with several blends of solvents in the literature to achieve the permeant intermediate wetting state.

Kumar (2006) evaluated the effectiveness of several surfactants on Berea sandstone cores and the best gas enhancement in the gas relative permeability was found to be as a factor of 2.1. The author used Novec FC 4430 as a two weight % surfactant that was dissolved in four weight % water and 94 weight % of methanol over a range of temperatures from 145^o F to 275^o F.

Bang (2007) reported an increase of both gas and condensate relative permeability by a factor of about two without any change of the initial gas permeability of the Berea and reservoir sandstone core samples. Several treatments were assessed yet, 1% of the 3M's FC4430 was observed to have the highest enhancement as a factor of 2.36 on Berea sandstone core plugs in the presence of 20% initial water saturation. The core sample then treated with the chemical mixed with 69.5 weight% 2-Butoxyethanol and 29.5 weight% Ethanol at a temperature of 175° F.

Bang et al. (2008) observed an improvement of the propped fracture multi-phase conductivity using a chemical treatment. A two weight % of L19945 as a chemical surfactant was mixed with propylene glycol and isopropanol blend by a ratio of 70/30 and 80/20 which increased the conductivity at a temperature of 279° F and a pressure of 1500 psig by a factor of 1.5 and 1.9, respectively.

Bang et al. (2010) used Novec FC4430 as a surfactant dissolved in several blends of solvents depending on the reservoir conditions, water saturation, and the brine salinity that was injected. The ratio that the solvents were mixed together were changing to accomplish the extreme advantage of the chemical treatment. For a temperature of 175° F, a mixture of 2-butoxyethanol (EGMBE) and ethanol in addition to 1 weight % of FC4430 was sufficient to give a 2.36 improvement factor with 19% initial water saturation.

3. METHODOLOGY

3.1 Sample Preparation

Two different size categories of Grey Berea Sand Stone cores were used throughout the experiments. Initially, one inch diameter and around two to three-inch length cores were used as screening cores to test the effectiveness of the treatment. Once the optimum treatment percentage was identified, longer cores of six-inch length were used to evaluate the treatment effectiveness on the 2-phase relative permeability.

The Grey Berea cores were purchased from Kocurek Industries, Inc. and were provided as several 12 inches cores in length and a block of 14 inches long by 7 inches wide by 7 inches height. To differentiate between these cores, a notation of “GB” was used to represent the cores taken from the Grey Brea 12 inches long cores. Another notation was used to represent cores taken from the Grey Berea Block, “BGB.”

All the above cores were cut using a cutting machine to have the desired length as shown in **Fig. 13**.

Figure 13. Core cutting machine.

After cutting, cores were dried in the oven at 100^{o} C for about 12 hours and then were taken out to cool down for a while. Once the cores cooled, both surfaces were polished to smooth any chips that occurred during the cutting. The polishing machine is shown in **Fig. 14**.

Figure 14. Core polishing machine.

After that, the cores were dried again in the oven for 12 hours and hot and cold weight were recorded. The caliper (**Fig. 15**) was used to measure the length and diameter of the cores by assuring the diameter of the same core is the same across the core.

Figure 15. Caliper

3.2 Porosity Apparatus and Procedure

Porosity measurements were conducted based on Boyle's Law: for a constant temperature in a closed system, the absolute pressure is inversely proportional to the volume of a given mass (Boundless, 2016). This relationship can be expressed mathematically as follows;

$$P \propto \frac{1}{V}$$

Which means: PV = constant and can be expressed as;

$$P_1V_1 = P_2V_2 \quad \text{--------------------------------} \quad (3.1)$$

Where,

P_1 and V_1 are the initial pressure and volume, respectively. Subscript 2 represents the second stage for both pressure and volume once the valve is opened and Helium is allowed to pass through the core sample.

To determine the porosity of a given core, the following steps are to be followed:

1- The core sample should be cut and smoothly polished.

2- Measure the core diameter, length, and dry hot weight. It is important to note that the length of the core shall not exceed **6 inches** otherwise the core will not fit inside the porosity core holder (**Fig.16**).

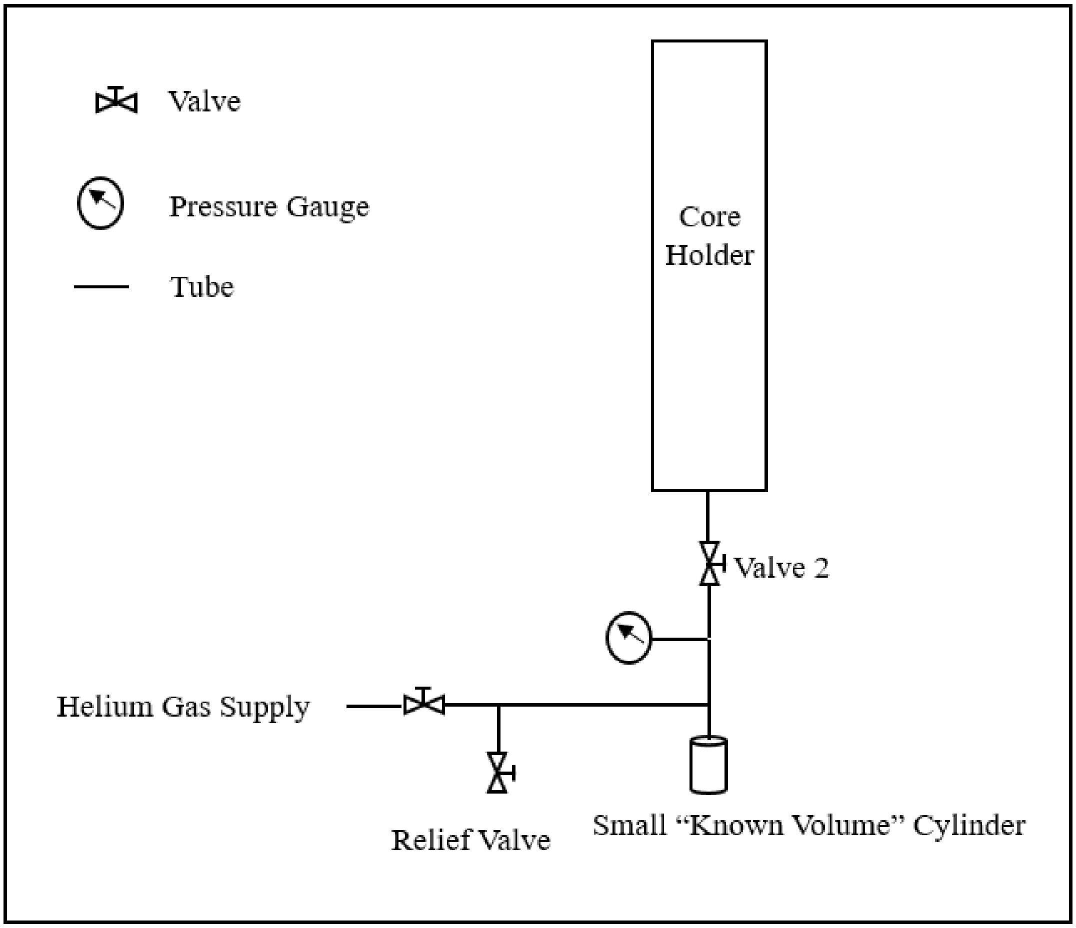


Figure 16. Porosity meter schematic

3- Pile the solid stainless-steel spacers until they are just taller than the core sample, as shown in **Fig. 17**, to avoid empty space inside the core holder as possible.

Figure 17. Spacers stacking

4- Spacers that were selected to be taller than the core sample are kept outside the core holder and their labels are noted.

5- The rest of the spacers are packed inside the core holder with the core sample and cap is closed tightly.

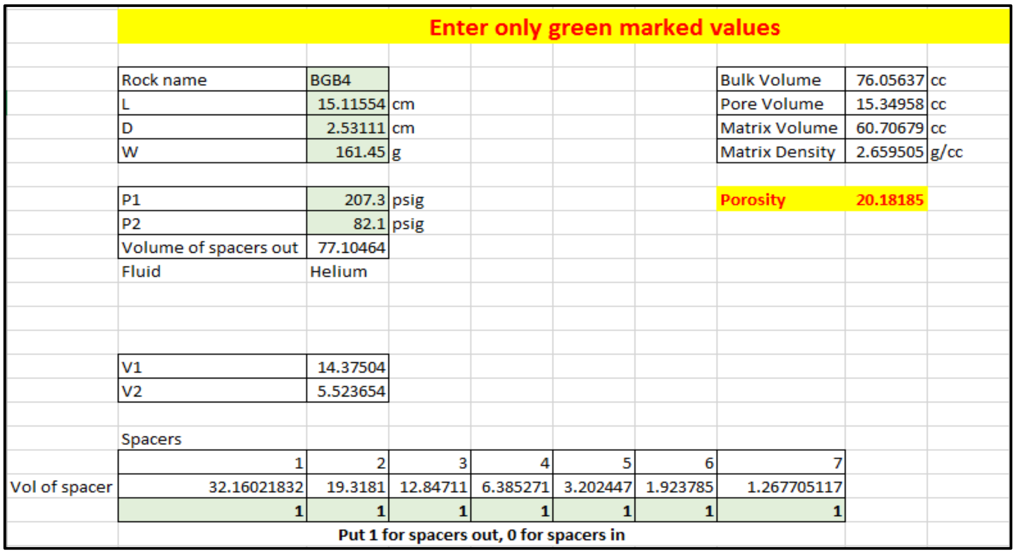
6- Close valve 2 and supply the system with Helium to a pressure around 207 psi. This pressure is recommended since the solid stainless-steel spacers were calibrated at 207 psi.

7- Wait for initial pressure (P_1) to stabilize then record it.

8- Open valve 2 and wait for final pressure (P_2) to stabilize then record it.

9- Use relief valve to release pressure and unpack the core sample.

10- Input the initial volume V_1, P_1 and P_2 to calculate V_2 using the excel spread sheet that was created to ultimately calculate porosity using initial pressure and volume as well as final pressure. These parameters calculate bulk and pore volumes and matrix density as shown in **Fig. 18**, utilizing equation (3.1).



Enter only green marked values

Rock name	BGB4	
L	15.11554	cm
D	2.53111	cm
W	161.45	g
P1	207.3	psig
P2	82.1	psig
Volume of spacers out	77.10464	
Fluid	Helium	
V1	14.37504	
V2	5.523654	

Bulk Volume	76.05637	cc
Pore Volume	15.34958	cc
Matrix Volume	60.70679	cc
Matrix Density	2.659505	g/cc
Porosity	20.18185	

Spacers

	1	2	3	4	5	6	7
Vol of spacer	32.16021832	19.3181	12.84711	6.385271	3.202447	1.923785	1.267705117
	1	**1**	**1**	**1**	**1**	**1**	**1**

Put 1 for spacers out, 0 for spacers in

Figure 18. Porosity calculation sheet

3.3 Permeability Setup and Procedure

Sometimes the term "absolute permeability" is used when only single fluid is flowing through the rock. Permeability is the quantitative measurement of the rock's capacity to allow fluid to flow and is measured in millidarcies. ("Permeability - Schlumberger Oilfield Glossary," n.d.)

Darcy's law (3.2) is used to measure the air absolute permeability of Berea core samples.

$$q = A * \frac{k\,(P_1^2 - P_2^2)}{2 * L * \mu * P_{sc}} \quad \text{-------------------------------} \quad (3.2)$$

Where,

P_1 is the inlet pressure in atm

P_2 is the outlet pressure in atm

P_{sc} is the reference pressure, also in atm

L is the core sample length in cm

A is the core sample area in cm^2

q is the flow rate in cc/sec

μ is the Nitrogen gas viscosity in cP.

k is the permeability in mD.

A schematic of the permeability setup is shown in **Fig. 19** below.

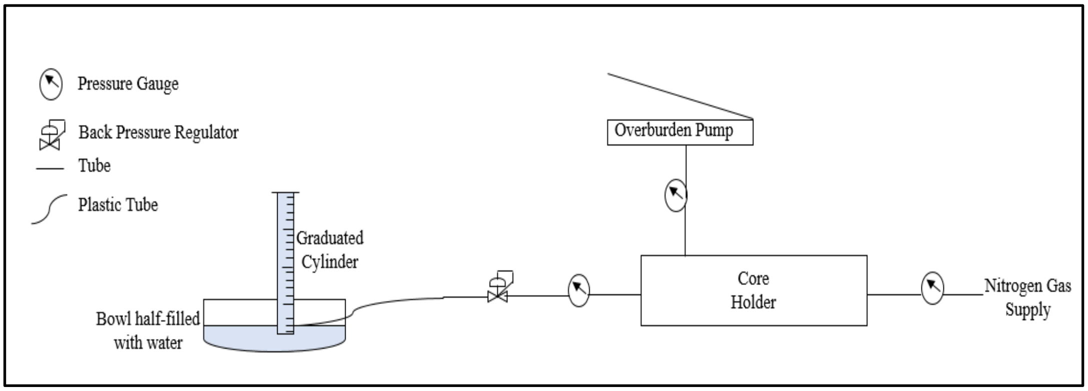


Figure 19. Permeability setup schematic

To determine the permeability of a core sample, follow the steps below:

1- Start with a smoothly cut core sample as described in **section 3.2**

2- Make sure to have a core holder that can hold cores with a diameter of 1-in. The core holder available in the lab can handle cores up to 12 inches long.

3- Make sure to connect pressure transducers before inlet of core holder and before the back-pressure regulator. This regulator allows control of the outlet pressure. Increase the outlet pressure over a specific interval to gradually reduce the flow rate.

4- Prepare a graduated cylinder filled with water and place it upside down on a bowl of water as shown in **Fig. 19**. The cylinder is held in place using a stand.

5- Prepare a plastic tube that connects the back-pressure regulator to the graduated cylinder.

6- Pack the core inside the core holder then use the available solid stainless steel spacers to compensate for the remaining empty space. These spacers have a hole in their centers to allow Nitrogen flow during the experiment.

7- Screw the cap tightly and apply a confining pressure. This confining pressure should be higher than the inlet pressure. During the permeability measurements, confining pressure between 1600 to 2000 psi was used.

8- Flow Nitrogen gas from the supply tank and increase the pressure until the desired inlet pressure is reached. Inlet pressure of about 160 psi was used.

9- Using back-pressure regulator, apply a pressure until outlet pressure reached 100 psi.

10- Make sure the graduated cylinder is filled with water and note the initial volume before the flow of Nitrogen gas.

11- Allow the Nitrogen gas to flow in the graduated cylinder through the plastic tube and record the time using a stop watch.

12- Once you take the plastic tube out of the graduated cylinder, stop the timing and record the final volume.

13- Increase the back-pressure using a desirable interval to obtain another flow rate reading. The interval used is 10 psi until the outlet pressure reached 150 psi then it changes to 2 or 3 psi.

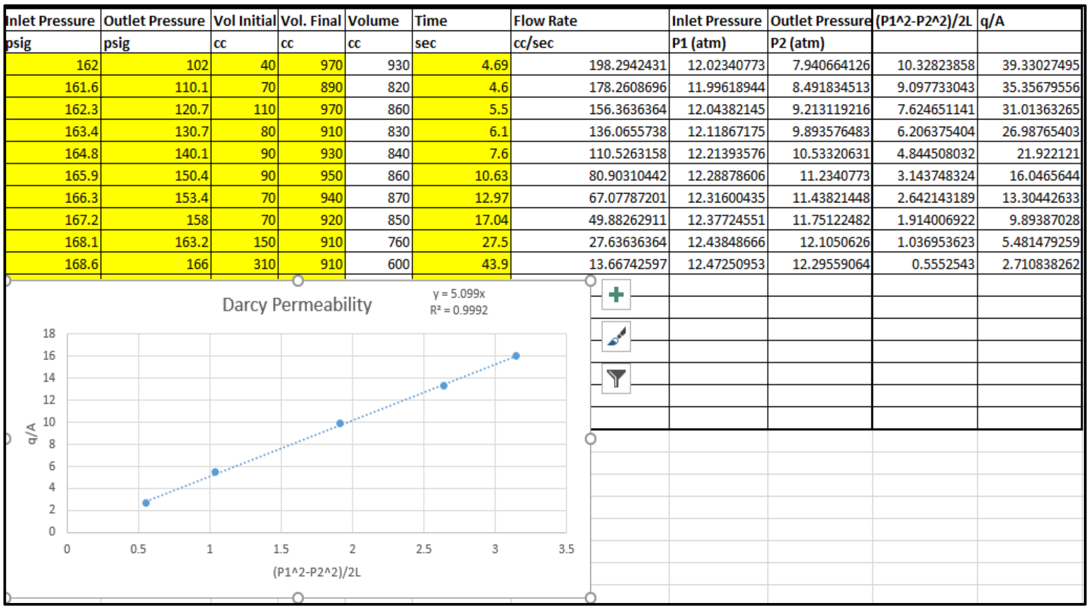
14- Record the new inlet and outlet pressures.

15- Repeat steps 10 through 14 until the flow rate is too low to record.

16- Close the Nitrogen supply and release pressure and confining pressure.

17- Unscrew the cap and unpack the core sample.

A plot of $\frac{q}{A}$ versus $\frac{P_1^2-P_2^2}{2L}$ was created over the laminar flow rates to determine the Darcy permeability using an excel spreadsheet as shown in **Fig 20**.



Inlet Pressure	Outlet Pressure	Vol Initial	Vol. Final	Volume	Time	Flow Rate	Inlet Pressure	Outlet Pressure	(P1^2-P2^2)/2L	q/A
psig	psig	cc	cc	cc	sec	cc/sec	P1 (atm)	P2 (atm)		
162	102	40	970	930	4.69	198.2942431	12.02340773	7.940664126	10.32823858	39.33027495
161.6	110.1	70	890	820	4.6	178.2608696	11.99618944	8.491834513	9.097733043	35.35679556
162.3	120.7	110	970	860	5.5	156.3636364	12.04382145	9.213119216	7.624651141	31.01363265
163.4	130.7	80	910	830	6.1	136.0655738	12.11867175	9.893576483	6.206375404	26.98765403
164.8	140.1	90	930	840	7.6	110.5263158	12.21393576	10.53320631	4.844508032	21.922121
165.9	150.4	90	950	860	10.63	80.90310442	12.28878606	11.2340773	3.143748324	16.0465644
166.3	153.4	70	940	870	12.97	67.07787201	12.31600435	11.43821448	2.642143189	13.30442633
167.2	158	70	920	850	17.04	49.88262911	12.37724551	11.75122482	1.914006922	9.89387028
168.1	163.2	150	910	760	27.5	27.63636364	12.43848666	12.1050626	1.036953623	5.481479259
168.6	166	310	910	600	43.9	13.66742597	12.47250953	12.29559064	0.5552543	2.710838262

Figure 20. Permeability calculation sheet

3.4 Spontaneous Imbibition Setup and Procedure

Spontaneous imbibition experiment is used as a sign to determine the effectiveness of the treatment. For that, a reference spontaneous imbibition is conducted for the cores before treatment. After treating the core, another spontaneous imbibition is conducted to analyze the recovery based on the spontaneous imbibition of the same wetting phase.

Spontaneous imbibition experiments were carried out using both normal-Decane and de-ionized (DI) water as wetting phases. It was observed that (DI) reduced the permeability of the cores by about 33% and there was a lower recovery towards the end which might be explained by the clay-swelling expansion of the Berea cores (**Table 2**).

Table 2. Permeability reduction after DI water imbibition

Core Sample	Dry Hot Weight, g	Dry Cold Weight, g	Length, in	Porosity, %	Permeability, mD
GB6 (short)	51.94	51.97	1.95	21.7	142
GB6 (short) Repeat		51.88	1.95	22.1	95

Due to the previous reasons, it was decided to continue with normal-Decane as the wetting phase for the rest of the research in order to avoid having to fire the samples.

The non-wetting fluid recovery is calculated using the equation below:

$$\frac{W_t - W_{FI}}{(\rho_{Decane} - \rho_{Air}) * V_P} \quad \text{--------------------------------} \quad (3.3)$$

Where,

W_t is the weight at time t in g.

W_{FI} is the initial weight with wire in the fluid which can be obtained by subtracting the final weight with wire in fluid from the final weight with wire in air then subtracting that from the initial weight with wire in air.

ρ_{Decane} is the density of the displacing fluid, i.e. normal-Decane.

ρ_{Air} is the density of the displaced fluid, i.e. air.

V_p is the pore volume of the core sample.

The spontaneous imbibition setup is shown in **Fig.21** below.

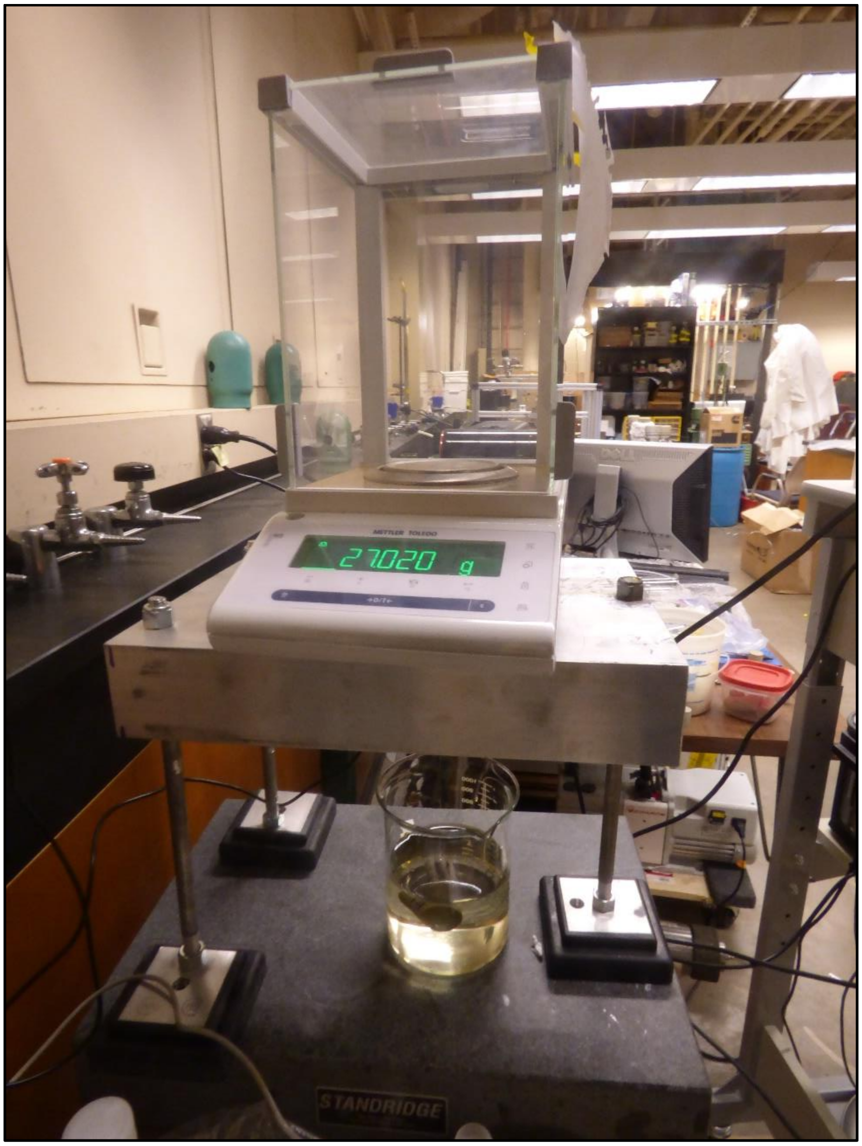


Figure 21. Spontaneous imbibition setup

To determine the spontaneous imbibition, follow the instructions below:

1- Make sure to have a scale with a hook from the bottom.

2- Place the scale on a stand with a hole from the top as shown in **Fig. 22**.

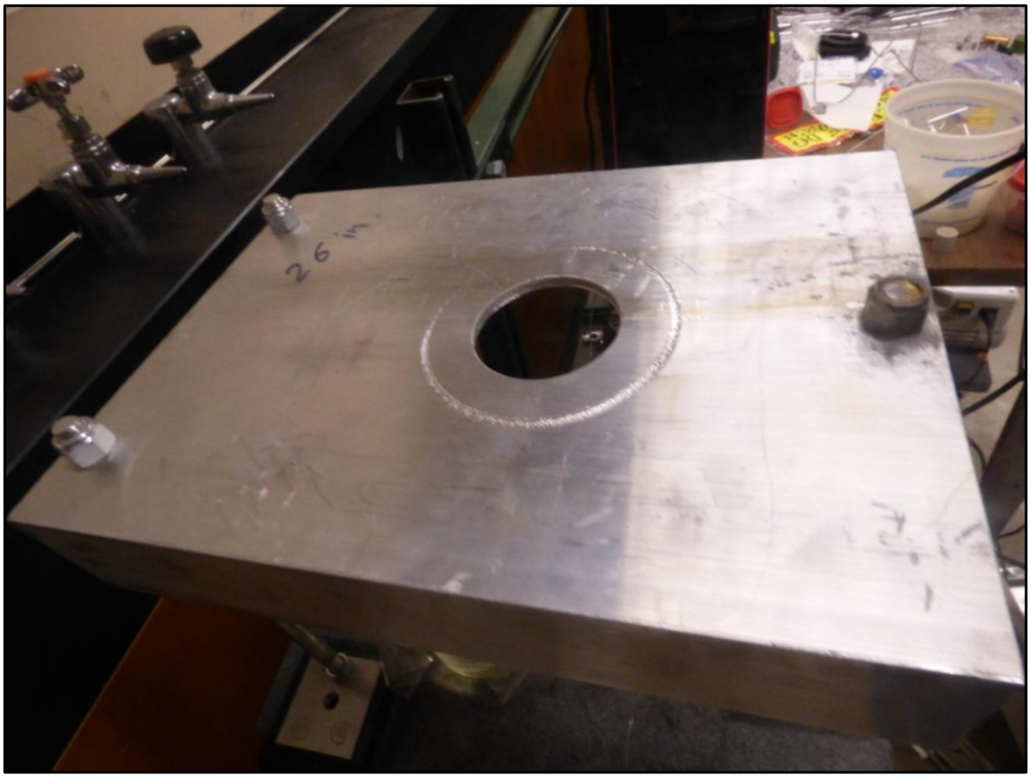


Figure 22. Stand with hole to hold scale

3- Prepare a hook to connect the scale to the core.

4- Attach the scale to a computer for continuous data recording, every 3 seconds for short cores and 0.5 seconds for long cores.

5- Core's porosity should be measured from **section 3.2**

6- Core's length, diameter and weight should be measured and recorded.

7- Find both displacing and displacement fluid densities from the relevant literature.

8- Use a fishing string to securely tie the core and make a knot so the core can hang on the hook.

9- Measure and record the initial weight of the core with the fishing string attached in air using the hook.

10- Connect the software and make sure it is recording the weight while the core sample is hanging.

11- Use a stop watch in one hand and with the other hand raise the core and lower it into the beaker filled with the wetting phase (DI water or normal-Decane).

12- Once the core hits the fluid, start the stop watch immediately.

13- From the computer monitor, record a time and simultaneously stop the stop watch to determine the zero time from the difference between the two times.

14- After about 24 hours, the final weight of the core while suspended in wetting fluid is recorded.

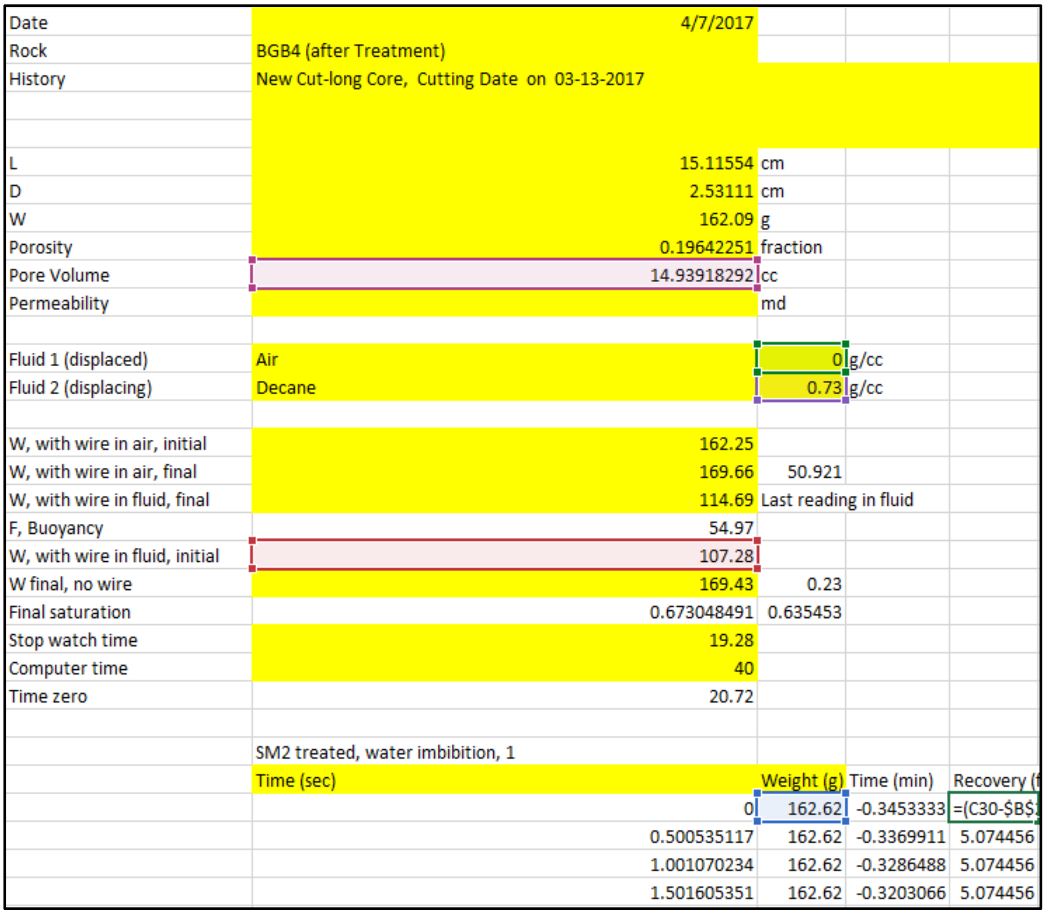
15- Take the core out of the fluid and remove the excess fluid from the core surface using a non-absorbing paper.

16- Measure and record the final weight of the core with the fishing string attached in air using the hook.

17- Remove the fishing string and record the final weight of the core without the wire in air.

18- Dry the core in oven for 6 to 12 hours.

A spreadsheet was made to calculate the recovery of the non-wetting phase using equation (3.3) as shown in **Fig. 23**.



Date	4/7/2017			
Rock	BGB4 (after Treatment)			
History	New Cut-long Core, Cutting Date on 03-13-2017			
L	15.11554	cm		
D	2.53111	cm		
W	162.09	g		
Porosity	0.19642251	fraction		
Pore Volume	14.93918292	cc		
Permeability		md		
Fluid 1 (displaced)	Air	0	g/cc	
Fluid 2 (displacing)	Decane	0.73	g/cc	
W, with wire in air, initial	162.25			
W, with wire in air, final	169.66	50.921		
W, with wire in fluid, final	114.69	Last reading in fluid		
F, Buoyancy	54.97			
W, with wire in fluid, initial	107.28			
W final, no wire	169.43	0.23		
Final saturation	0.673048491	0.635453		
Stop watch time	19.28			
Computer time	40			
Time zero	20.72			
	SM2 treated, water imbibition, 1			
	Time (sec)	Weight (g)	Time (min)	Recovery (f
	0	162.62	-0.3453333	=(C30-B
	0.500535117	162.62	-0.3369911	5.074456
	1.001070234	162.62	-0.3286488	5.074456
	1.501605351	162.62	-0.3203066	5.074456

Figure 23. Recovery calculation sheet

3.5 Chemical Treatment

Treatment **SA-17** as we decided to call it was supplied to be tested. The surfactant of this treatment contains up to 90% fluorinated substances which attach to the surface of the sandstone rock. **Fig.24** shows a chemical structure of a similar surfactant to the one used to conduct the wettability alteration. This treatment was evaluated using two different solvents and at two different temperatures.

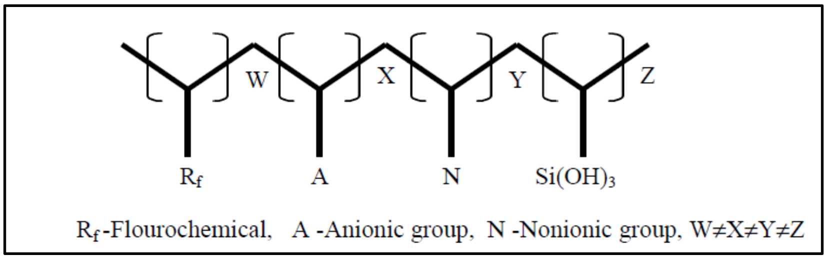


Figure 24. Flourochemical surfactant chemical structure (Tang et al., 2000)

3.5.1 High Temperature Approach

To conduct the treatment at high temperature, an oven that has three different ports is used to raise the temperature to 180^o F ~ (83^o C). **Fig.25**. shows the schematic for the oven and the High Temperature system.

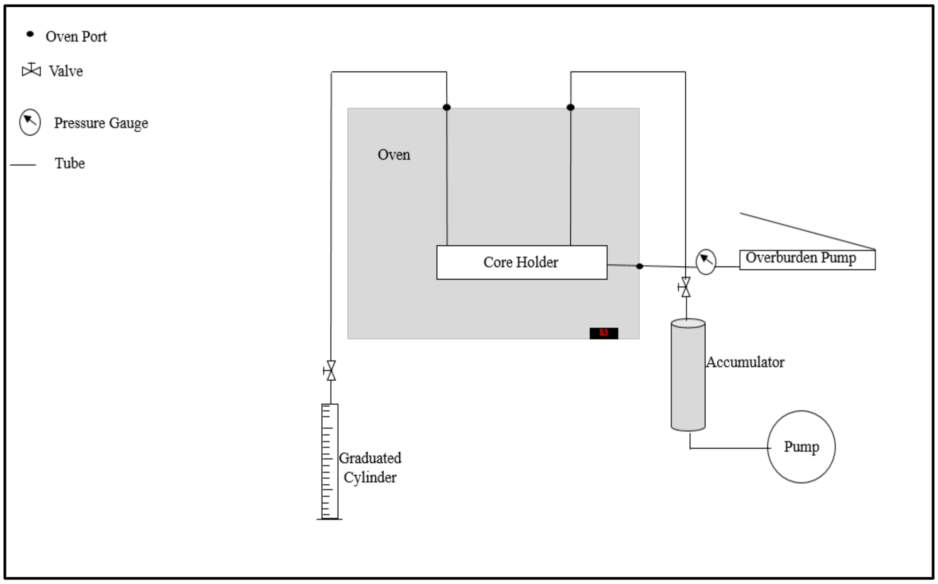


Figure 25. High temperature system schematic

Before starting the actual treatment, core weight, porosity, permeability and normal-Decane imbibition should be measured. The core is placed inside the core holder and the latter is placed inside the oven. Then apply an overburden pressure of about 200 psi and monitor it as pressure increases with temperature.

Initially, the treatment surfactant was mixed with small percentage of de-ionized water and a ratio of both Propylene glycol and Isopropanol under high temperature. Later, based on the results, it was decided to remove the water from the solvent blend and instead inject a small amount of de-ionized water just before injecting the treatment to introduce initial water saturation to the core.

After thermal stability is reached and no further increase of overburden pressure is observed, follow the steps below:

1- Calculate the required weight of each component based on their specific percentages and the desired total weight.

2- Record the weight of an empty beaker.

3- Use pipette and start pouring the first solvent that has the highest weight percentage until the weight of both beaker and solvent is reached.

4- Add the second solvent until the total weight of both solvents and beaker is obtained.

5- Similarly, add the surfactant until the total weight is matched as shown is **Table. 3**.

Table 3. Target and actual measurements for both surfactant and solvent

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	171.72
67.2	67.22	2	1+ 70.03% 2-butoxyethanol of Solvent	238.94
28.8	28.77	3	2+ 29.97% ethanol of Solvent	267.71
4	4.04	4	3+ 4.04% SA-17 of Solution	271.75

6- Blend the mixture for one minute and let it settle for some time while injecting de-ionized water.

7- Inject de-ionized water at 2 cc/min until water droplets start to appear from outlet line.

8- Stop the injection and start injecting the treatment at the same rate (2 cc/min). Wait until 5 pore volume is recovered before stopping the treatment injection.

9- Once treatment injection is stopped, close both inlet and outlet valves and age the core inside the core holder under high temperature for 12 hours.

10- Open the inlet valve only and inject air for 5 to 8 minutes before turning the outlet valve on.

11- Keep the air flowing while both valves are open for an hour.

12- Shut the air supply and turn off the oven until it cools down to unpack the core and record its wet weight.

13- Dry the core for 12 hours and record both hot and cool dry weights.

3.5.1.1 Optimizing the Solvent Selection

The ratio of the two solvents was selected from the literature but both combinations of Propylene Glycol/ Isopropanol and Butoxyethanol/Ethanol were tested to be successful solvents with different surfactants. To optimize that selection, a small experiment was done using microscopic glass slides. The steps of this test are as follows:

1- Calculate the required weight of each component based on their specific percentages and the desired total weight.

2- Record the weight of an empty beaker.

3- Use pipette and start pouring the first solvent that has the highest weight percentage until the weight of both beaker and solvent is reached.

4- Add the second solvent until the total weight of both solvents and beaker is obtained.

5- Similarly, add the surfactant until the total weight is matched.

6- Blend the mixture for one minute and let it settle for one to five minutes.

7- Place the glass slide in de-ionized water for five minutes.

8- Take the glass slide out of the de-ionized water and put it in treatment mixture.

9- Place the beaker that has both treatment and glass slides in oven at Temperature of 180^o F for 4 hours.

10- Take the glass slide out of the beaker and put the slide back in oven for one hour then let it cool down for half an hour.

11- Conduct Contact Angle, which will be explained next in **section 3.6**, to get the best combination of solvent and surfactant weight percentages as shown in **Fig. 26**.

Figure 26. Contact angle of a 70/30 2-butoxyethanol/ethanol on a glass slide (Left 4% of SA-17, Right 0% of SA-17)

3.5.2 Low Temperature Approach

This step was conducted after the results of the high temperature approach. It was done at room temperature with similar system to the high temperature excluding the oven as shown in **Fig. 27**.

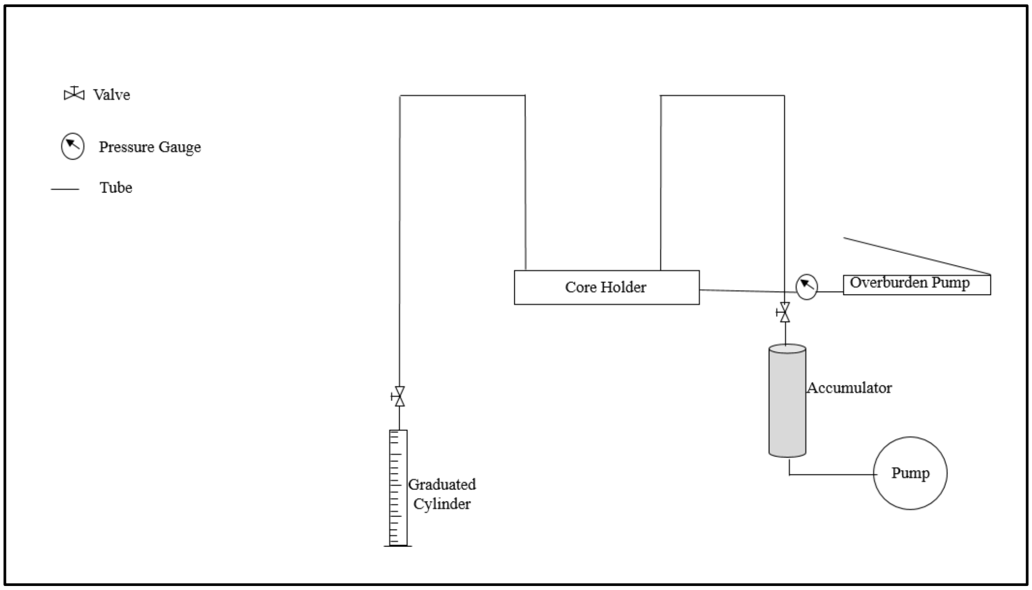


Figure 27. Low temperature system schematic

To conduct this test, follow the steps below:

Repeat steps 1 through 9 in **section 3.5.1** then record the wet weight of the core after aging and dry it. After drying, measure the core hot and cold weight.

3.6 Contact Angle

Another method to measure the effectiveness of the treatment is to conduct the contact angle test. Wu & Firoozabadi (2010) reported that for the treated core, a contact angle of 110 to 140° is considered as water-wet while a contact angle ranging from 45 to 80° is oil wet when the angle is measured through the oil phase.

For this test, a camera fixed in place using a three pods stand is used. The treated core is placed on a stage located close to the camera as shown in **Fig. 28**.

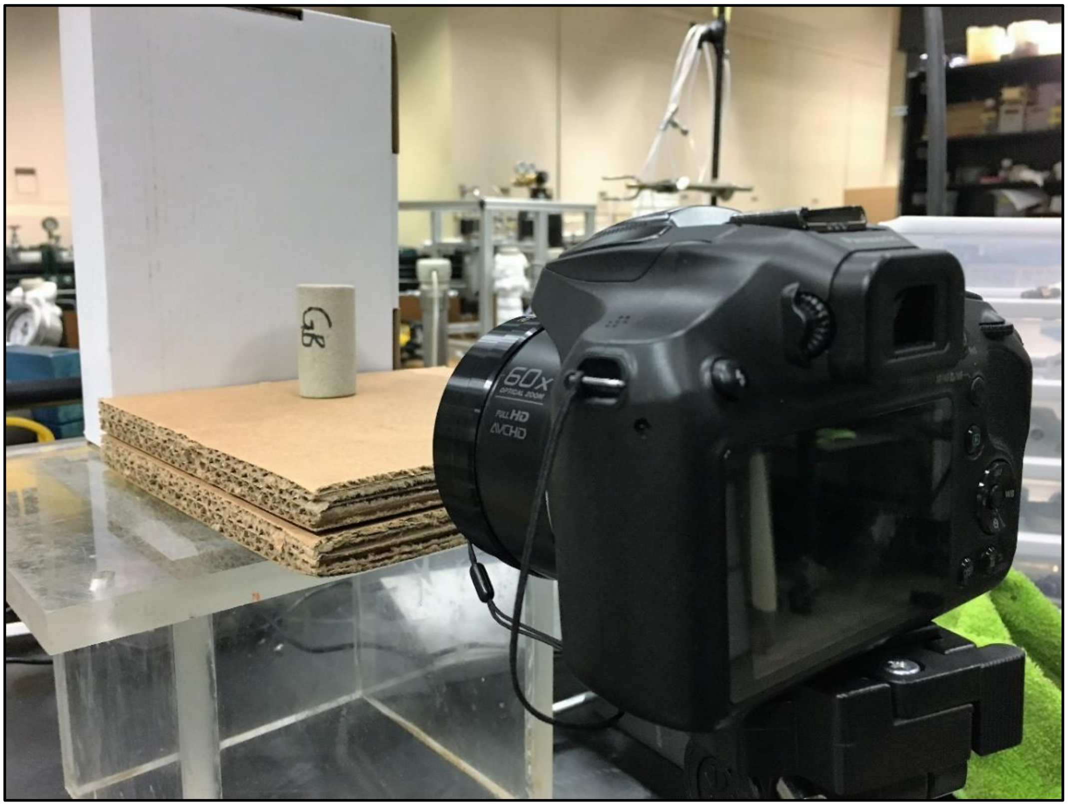


Figure 28. Camera stage setup

Using the three pods stand, adjust the elevation of the camera until the top surface of the core appears as a straight line from the camera lens. Make sure to prepare the focus before placing either normal-Decane or de-ionized water. Use pipette and drop one at a time and take a picture, simultaneously. Finally, use ImageJ software to determine the maximum elevation angle then double that angle to get the required contact angle.

3.7 Relative Permeability

Relative permeability is the last test to examine the feasibility of the chemical treatment. This test should be conducted using a long core, 6 inches long and it is conducted before treatment to have a reference relative permeability curve of Berea core and then after treatment. Before starting the relative permeability experiment, the core is fully saturated with the wetting phase, normal-Decane in this case.

3.7.1 Saturation Setup and Procedure

Saturation setup consists of cold trap to freeze any liquid before entering the vacuum pump. The cold trap is connected to both a flask using a pipe that has two valves to isolate the cold trap and a pressure gauge. From the main pipe, another small connection that can be isolated using a different valve connected to a beaker that is filled with the saturation fluid as shown in the following schematic.

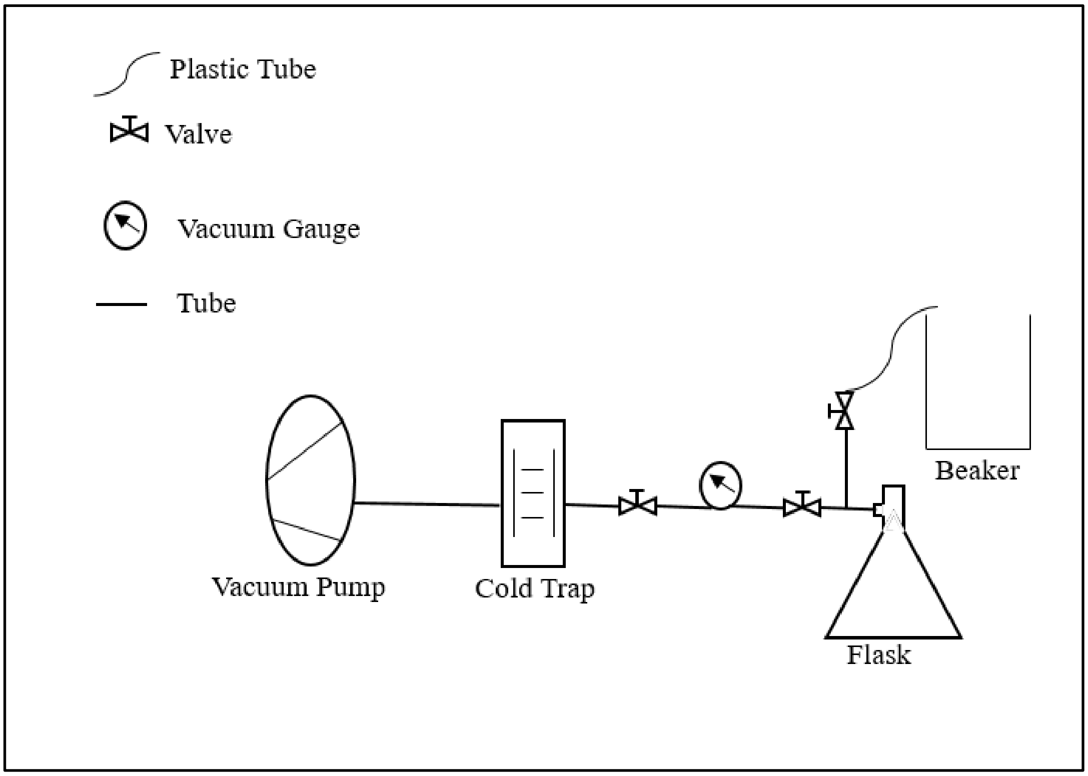


Figure 29. Saturation setup

To saturate a core, follow the steps below:

1- Measure the weight of the core before saturation.

2- Obtain the density of the saturation fluid from literature.

3- Obtain the core pore volume from the porosity spreadsheet used in **section 3.2**.

4- Connect the flask to the cold trap using the connection pipe.

5- Place the core inside the flask and close it from the top.

6- Make sure valves that connect cold trap to the flask are open.

7- Close the valve that connects the beaker to the flask.

8- Start the cold trap for one hour then start the vacuum pump for another hour while cold trap is on. Fill the tube from the beaker to the valve once you start the vacuum to avoid any air in the system.

9- Close valves that connect the flask to cold trap and vacuum pump and fully open the valve connecting the beaker to raise the saturation fluid.

10- Once core inside the flask is fully covered by the saturation fluid, close the valve and turn off both vacuum and cold trap.

11- Wait 20 minutes then take out the core and measure the core's weight after saturation.

12- Use equations (3.4) and (3.5) to calculate the core saturation.

$$V_o = \frac{W_{sat} - W_{dry}}{\rho_{N-Decane}} \quad \text{--------------------------------} \quad (3.4)$$

$$S = \frac{V_o}{V_P} \quad \text{--------------------------------} \quad (3.5)$$

3.7.2 Irreducible Oil Saturation

After saturating the core to almost 100%, pack the core inside the core holder as shown in the **Fig. 30** and follow the below steps:

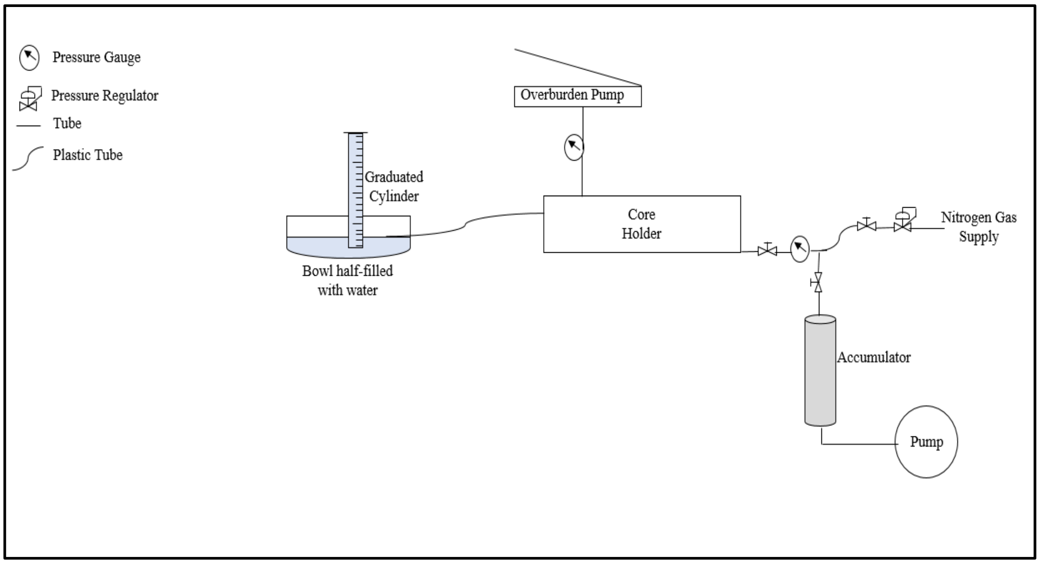


Figure 30. Relative permeability setup

1- Make sure the Nitrogen Valve is closed.

2- Fill the lines with normal-Decane until it starts dropping from the core holder cap to assure no air in the lines.

3- Close the cap tightly and inject normal-Decane at low rate, 2 cc/min and monitor pressure until it stabilizes.

4- Once pressure stabilizes, increase the injection rate to 4 cc/min and monitor the pressure until it stabilizes.

5- Stop the normal-Decane injection and once pressure is depleted close the valve.

6- Open the Nitrogen valve and inject Nitrogen at constant pressure of 10 psi and monitor the rate until it stabilizes. Use two stop watches, one to note the start of the Nitrogen injection and the other one for rate measurements.

7- Once the Nitrogen rate is stabilized, close the Nitrogen using the regulator until the pressure goes to zero then close the valve.

8- Unpack the core holder and measure the weight of the core.

9- Calculate the gas effective permeability at irreducible oil saturation using equation (3.2).

10- Divide the gas effective permeability over the absolute permeability to get the gas relative permeability at irreducible oil saturation.

11- Use both equations (3.4) and (3.5) to determine the irreducible oil saturation.

3.7.3 Co-Injection

Before starting the co-injection of both normal-Decane and the Nitrogen gas, calculate the initial normal-Decane rate using the equations below for a target relative permeability value:

$$q = A * \frac{k_o \, (P_1 - P_2)}{L * \mu * P_{sc}} \quad \text{------------------------} \quad (3.6)$$

$$k_o = k * k_{ro} \quad \text{------------------------} \quad (3.7)$$

1- Start the normal-Decane injection at the calculated rate and quickly use the Nitrogen regulator to inject Nitrogen gas until pressure reaches 10 psi.

2- Measure the rate of the Nitrogen gas at different time periods until it stabilizes.

3- Once stabilized, stop the Nitrogen injection, and quickly stop the normal-Decane injection by stopping the pump.

4- Unpack the core and measure its weights to calculate its saturation after the co-injection.

5- Increase the normal-Decane rate gradually and repeat steps 1 through 4 until Nitrogen rate is too small to be measured.

6- Calculate gas relative permeability as described in **section 3.7.2** and oil relative permeability and oil saturation at each injection rate using equations (3.6) and (3.7) to create the relative permeability plot.

3.7.4 Irreducible Gas Saturation

Once there is no longer enough Nitrogen gas to be measured, close the Nitrogen valve and inject normal-Decane at higher rate than was injecting previously and monitor pressure until it stabilizes. Once stabilization is obtained, unpack the core holder and weigh the core to determine the irreducible gas saturation in addition to the oil relative permeability at that saturation.

4. RESULTS AND DISCUSSION

4.1 Porosity and Permeability

Porosity and permeability measurements were conducted for all core samples before treatment and then later after the treatment. This was done to examine the impact of the treatment on both porosity and permeability of each core. Porosity measurements were not affected by the treatment while permeability reduced up to 29% with 4% of treatment as shown in **Table. 4**, which shows porosity and permeability of Grey Berea before and after treatment as well as the percentage change in permeability after treatment.

GB2-2 permeability of 124 mD was repeated because the non-darcy permeability was measuring negative slope. **Table 4**. shows that the repeated permeability of GB2-2 is 118 mD which was reproduced after treatment. This treatment was not injected into the core because the inlet valve was kept closed by accident.

4.2 Spontaneous Imbibition

Spontaneous imbibition was done at room temperature and pressure, and each experiment was left for about 24 hours before measuring the final recovery. Spontaneous imbibition experiments were conducted using de-ionized water as a wetting phase at the beginning but it resulted in a reduction in permeability. It was also observed that the recovery curve experiences a decrease following 30 min of imbibition time forming a “hump” as shown in **Fig. 31.** This was attributed to clay swelling.

Table 4. Porosity and permeability before and after treatment

*Core Sample	Length, in	Porosity, %	Permeability, mD	% reduction in permeability
GB2-1	1.83	20.7	135	31%
GB2-1 (after Treatment)	1.83	20.9	93	
GB2-2	1.87	20.7	124	
GB2-2 Repeat	1.87	20.7	118	0.21%
GB2-2 (after Treatment)	1.87	22.6	118	
GB2-2 (after 2nd Treatment)	1.87	20.8	109	7%
GB2-3	1.87	21.2	138	18%
GB2-3 (after 1st Treatment)	1.87	21.7	113	3%
GB2-3 (after 2nd Treatment)	1.87	21.4	110	
BGB1-1	1.94	19.9	74	10%
BGB1-1 (after 1st treatment)	1.94	20.4	66	
BGB1-2	1.76	21.4	91	15%
BGB1-2 (after 1st Treatment)	1.76	20.5	77	
BGB2	6.01	20.6	118	13%
BGB2 (after Treatment)	6.01	19.2	103	
BGB3	5.97	20.1	119	
BGB4	5.95	20.2	119	29%
BGB4 (after Treatment)	5.95	19.6	85	
BGB5-1-1	1.42	21.8	82	23%
BGB5-1-1 (after Treatment)	1.42	21.8	63	
BGB5-1-2	1.55	21.0	91	-2%
BGB5-1-2 (after Treatment)	1.55	19.5	92	

*All cores have 1-inch diameter

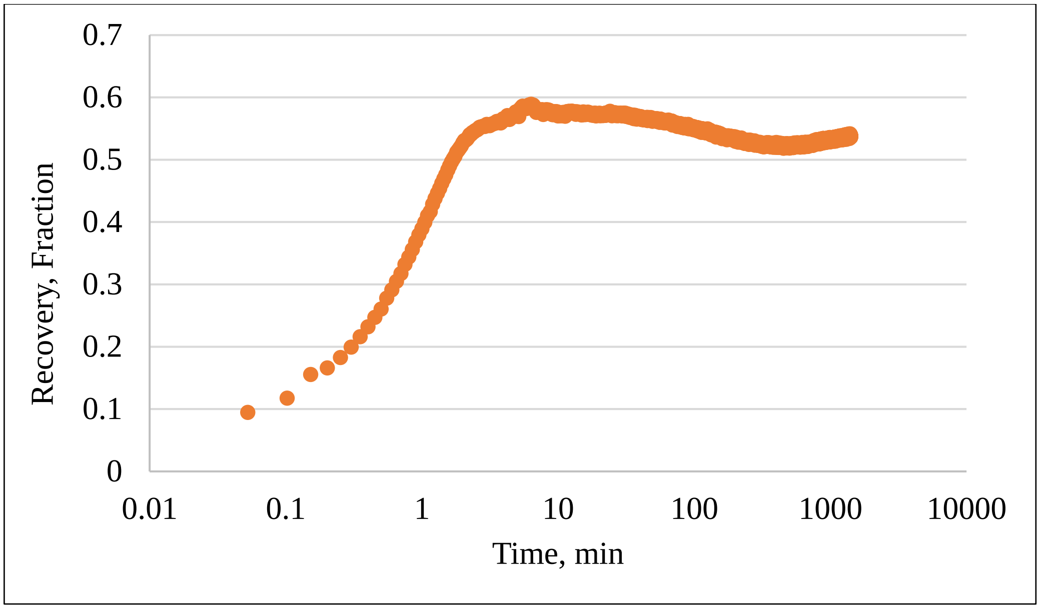


Figure 31. GB5 (small) water spontaneous imbibition

Fig. 32 shows a comparison of the decane imbibition of BGB5-1-2 before and after treatment of 8%. It shows clearly that the treatment reduces the imbibition rate. The early reduction in the recovery curve explains that the treatment altered the wettability of the core to gas-wet thus slowing down the decane when entering the core to displace the gas. The results of other imbibition tests are shared in a later section.

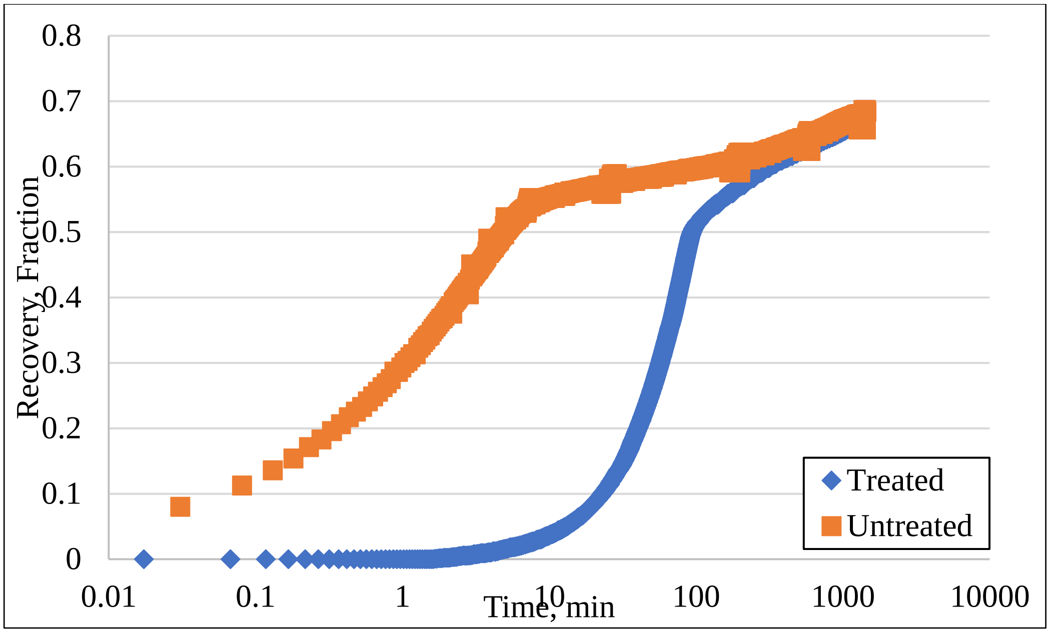


Figure 32. Decane imbibition comparison before and after treatment of 8%

4.3 Chemical Treatment

Several percentages of the surfactant were tested using two different solvents on screening cores (short cores) except the last two treatments that were done on large cores (BGB4 and BGB2). The injection rate was kept constant at 2 cc/min for both treatment and de-ionized water throughout the experiments. The presence of water is essential to allow for the adsorption of the chemical.

4.3.1 Optimizing the Solvent Selection

Initially, the surfactant was tested using a mixture of propylene glycol/ isopropanol and de-ionized water. After several tests, it was decided to have a solvent with only 70/30 ratio of propylene glycol/ Isopropanol. Based on the previous attempts, it was decided to conduct a contact angle qualitative comparison between 70/30 ratio of propylene glycol/ Isopropanol and 2-butoxyethanol/ethanol on glass slides using different surfactant percentages to optimize the selection of the solvent. At 181° F, 0% and 4% of the surfactant were added to both solvent mixtures to see the impact of the solvents as shown in **Fig. 33** and **Fig. 34.**

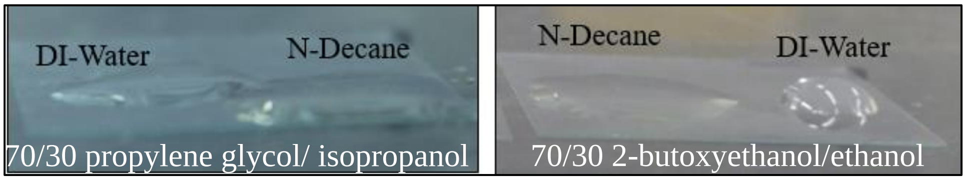


Figure 33. Contact angle of a 0% surfactant on a glass slide (control sample)

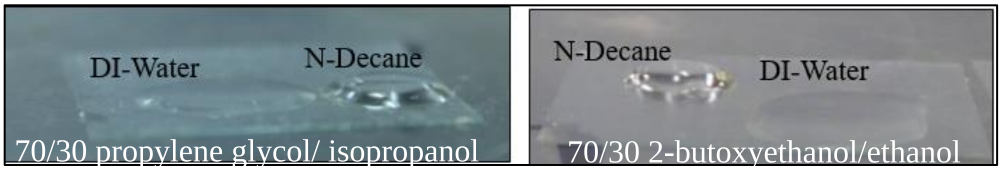


Figure 34. Contact angle of a 4% surfactant on a glass slide

Fig. 33 and **Fig. 34** show that 70/30 combination of 2-butoxyethanol/ethanol is more effective with the surfactant than propylene glycol/ Isopropanol blend.

4.3.2 High Temperature Treatments

Initially all tests were conducted at high temperatures using different surfactant percentages and different solvents. Using this method, the cores were aged at a high temperature inside the core holder for 12 hours and then permeability, contact angle, and spontaneous imbibition were measured. The tables below document all high temperature treatment attempts.

4.3.2.1 GB2-1 (1.28%)

This treatment was the first treatment and was conducted at a temperature of 150^o F. The solvent contained 5% of de-ionized water which was mixed with the other two chemicals and 2% of the surfactant as shown in **Table 6.** The treatment was injected at a rate of 2 cc/ min for 30 minutes before letting the air flow for 5 minutes while the outlet valve was closed without aging. After that, the outlet valve was opened and air flowed for 40 minutes. **Table 5** shows the amount of the chemical volumes that were collected at the outlet valve before and after air flow in addition to the core's wet and dry weights.

During this treatment, the heat was not allowed to reach thermal stability and the core was not aged. So, it was decided to allow the heat to stabilize and age the core for about 12 hours during the following treatments.

The permeability measurements showed a reduction of about 31% as shown in **Fig. 35**. This significant reduction could be due to the amount of de-ionized water in the solvent mixture.

Table 5. GB2-1 treatment data

Core Sample	**BG2-1**
Date	2/12/2017
Confined Pressure, psi	800-1500
Oven Temperature, F	150
Oven Temperature, C	65.56
Pumping Rate, mL/min	2
Pumping Time, min	30
Collected Chemical Volume, cc	50
Collected Chemical Volume after Air flowing for 5 min with closed valve followed by 40 mins open valve, cc	35
Remained Chemical Volume in Accumulator, cc	20
Core Weight After Treatment, g	51.74
Core Dry Weight, g	49.37

Table 6. GB2-1 target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	169.68
38.4	38.40	2	1+ 63.97% Propylene glycol	208.08
17.4	17.40	3	2+ 28.99% Isopropanol	225.48
3	3.46	4	3+ 5.79% DI water	228.94
1.2	0.77	5	4+ 1.28% SA-17	229.71

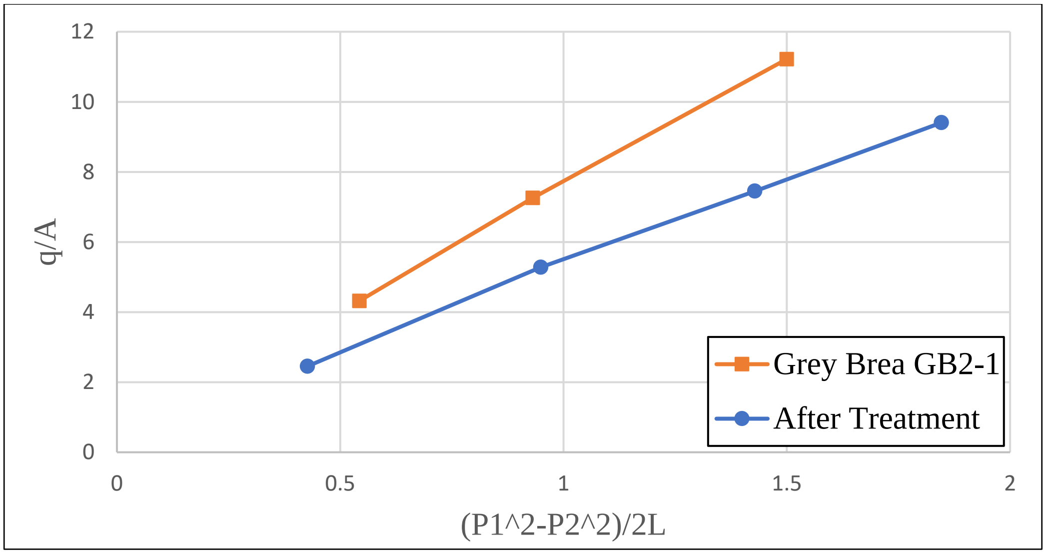


Figure 35. 31% reduction of permeability after treatment, show through a reduction in slope

Fig. 36 shows a normal-decane spontaneous imbibition comparison before and after the treatment. It shows that the treatment slightly increased the imbibition instead of reducing it.

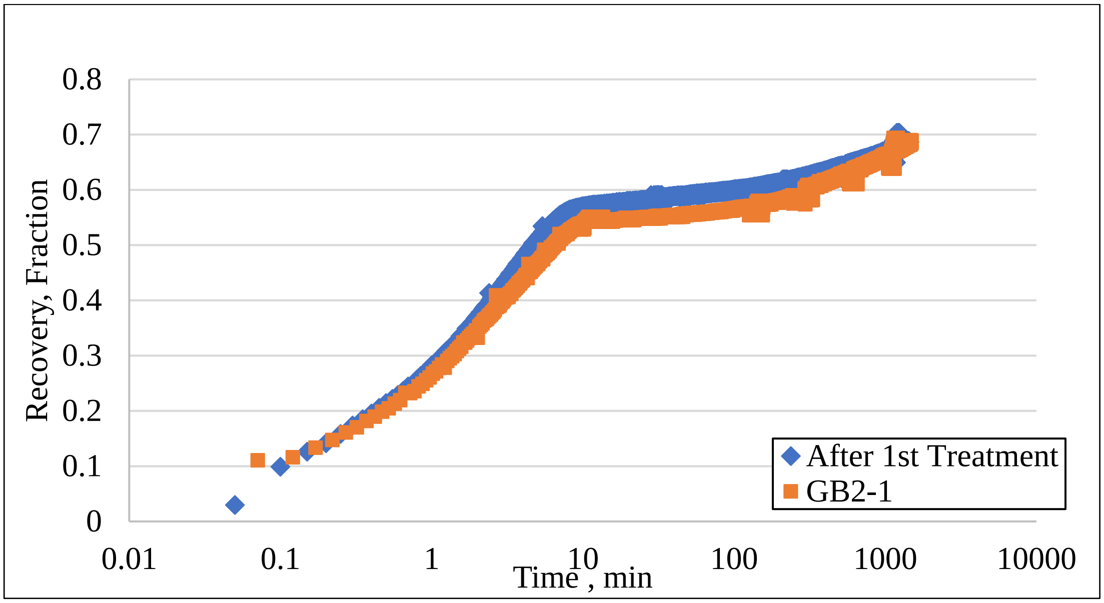


Figure 36. GB2-1 decane spontaneous imbibition before and after treatment

4.3.2.2 GB2-2

This core was treated twice since the first treatment did not reach the core due to unintentional human error of injecting the treatment while the inlet valve was kept closed.

4.3.2.2.1 First Treatment (1.92%)

During this treatment, temperature was allowed to reach stability at 180^o F for about 4 hours before injecting the treatment as shown in **Table 8**.

Both solvents and surfactant weight percentages were kept the same as previously tested in GB2-1. **Table 7** shows the planned and actual measurements and percentages. The treatment was injected for 30 minutes and no chemical was recovered from the outlet valve. The core was aged for about 13 hours at 180^o F before air flowed for 5 minutes while the outlet valve was closed and opened for 50 minutes while the air flowed. No chemical was collected at the outlet as well since the treatment was accidently not injected to the core.

During this treatment, the heat was not stabilized at the time of the injection and the treatment did not reach the core which was confirmed by the permeability measurements that reduced by 0.21% due to measurement error as shown in **Fig. 37**

Table 9 summarizes the treatment data and the core's wet and dry weights.

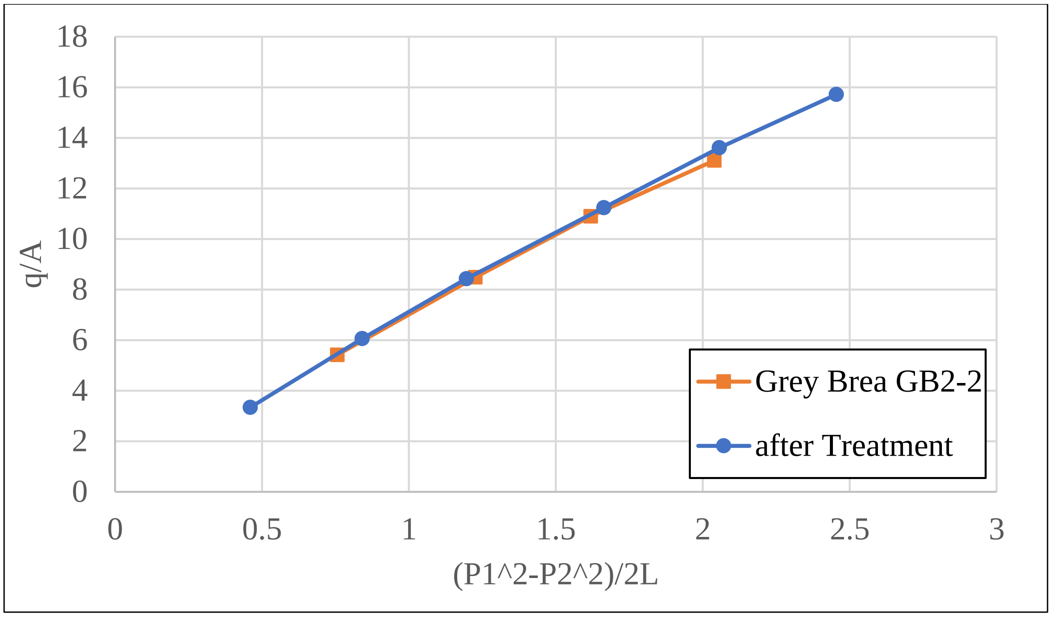


Figure 37. Constant permeability after treatment

Table 7. GB2-2 first treatment target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	60.05
		1	Beaker	167.86
38.4	38.43	2	1+ 64.00% Propylene glycol	206.29
17.4	17.39	3	2+ 28.96% Isopropanol	223.68
3	3.08	4	3+ 5.13% DI water	226.76
1.2	1.15	5	4+ 1.92% SA-17	227.91

Table 8. GB2-2 first treatment thermal stability data

Actual Time	Time, min	Overburden Pressure, psi	Note
7:20 PM	0	500	
	15	600	
	30	890	
	45	1250	
	60	1650	
	75	1995	Pressure Released
8:41 PM	0	1000	
	15	1300	
	30	1550	
	45	1800	
	60	2000	Pressure Released
9:43 PM	0	1000	
	15	1210	
	30	1400	
	45	1500	
	60	1650	
	75	1775	
	90	1850	
	105	1950	Pressure Released
11:35 PM	0	800	Start Injecting
12:05 AM	30	1050	
7:00 AM	415	1500	
10:54 AM	234	1550	
12:53 PM	119	1550	Start air Flow
2:04 PM	71	1550	Stop air Flow

Table 9. BG2-2 first treatment data

Core Sample	**BG2-2**
Date	2/17/2017
Confined Pressure, psi	800-1550
Oven Temperature, F	180
Oven Temperature, C	82.22
Pumping Rate, mL/min	2
Pumping Time, min	30
Collected Chemical Volume, cc	0
Collected Chemical Volume after Air flowing for 5 min with closed valve followed by 50 mins open valve, cc	negligible
Remained Chemical Volume in Accumulator, cc	0
Core Weight After Treatment, g	52.14
Core Dry Weight, g	50.26

4.3.2.2.2 Second Treatment (4.21%)

For this treatment, de-ionized water was removed from the solvent blend and a very small amount of water was injected right before the treatment to activate the surfactant as shown in the tables below. This treatment was done to treat GB2-2 since it the first treatment attempt did not reach the core. The thermal stability was reached after about 19 hours at a temperature of 181^{o} F. A ratio of 70/30 propylene glycol and isopropanol was blend together before adding 4% of the surfactant and injected for 31 minutes. **Table 10** shows the planned and actual measurements and percentages of both the solvent and the surfactant used for this treatment. After the treatment injection, 37 cc of solution was collected before the core was aged, 6 cc of which was de-ionized water. The core then was aged at a high temperature for 13 hours before letting the air flow and 20 cc was recovered as shown in **Table 11**.

Table 10. GB2-2 second treatment target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	287.39
40.32	40.35	2	1+ 70.02% Propylene glycol of Solution	327.74
17.28	17.28	3	2+ 29.98% Isopropanol of Solution	345.02
2.4	2.53	4	3+ 4.21% SA-17	347.55

Table 11. BG2-2 second treatment data

Date	3/13/2017
Confined Pressure, psi	1000
Oven Temperature, F	181.40
Oven Temperature, C	83.00
Treatment Stirring Time, min	1.00
Treatment Settling after Stirring Time, min	32.00
DI Water Pumping Rate, mL/min	2
Treatment Pumping Rate, mL/min	2
DI Water Pumping Time, min	3.53
Treatment Pumping Time, min	31.52
Total Prepared Treatment Volume, cc	100
Collected DI Water and Chemical Volume before aging, cc	37
DI Water Volume, cc	6
Collected Chemical Volume before aging, cc	31
Collected Chemical Volume after Air flowing for **8** min with closed valve followed by **60** mins open valve, cc	20
Remained Chemical Volume in Accumulator, cc	0
Core Weight After Treatment, g	51.97
Core Dry Hot Weight, g	50.27

To examine the effect of the treatment, permeability after treatment was measured and compared to the permeability before treatment as shown in **Fig. 38**. After this treatment, the permeability reduced by 7%.

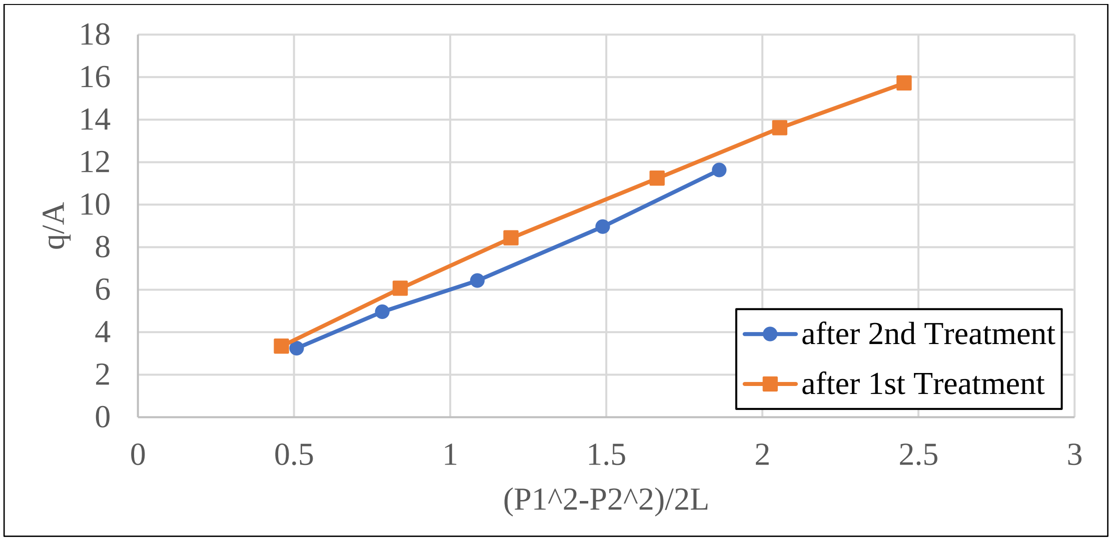


Figure 38. GB2-2 “7%” permeability reduction after the second treatment

The normal decane imbibition comparison between GB2-2 before and after the second treatment shows an opposite effect of the treatment as the recovery increased at the beginning which allows a little more decane to imbibe to the core as shown in **Fig. 39**.

Also, a contact angle experiment was conducted after this treatment, but the core adsorbed both de-ionized water and normal decane drops as shown in **Fig. 40**.

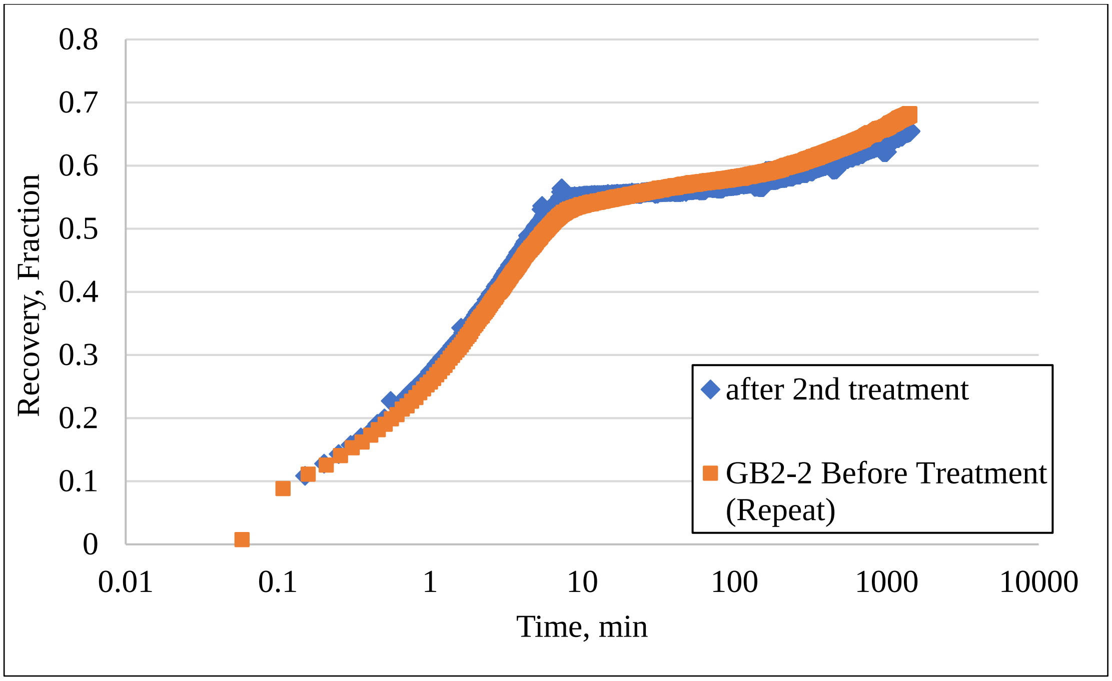


Figure 39. GB2-2 decane spontaneous imbibition before and after treatment

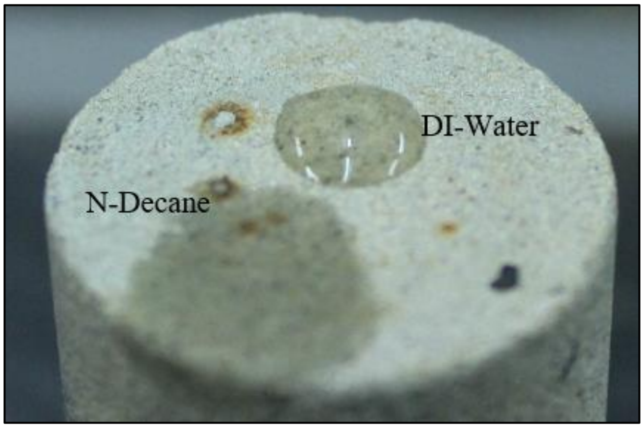


Figure 40. Contact angle of GB2-2 after 4.21% treatment

4.3.2.3 GB2-3

This core was treated twice, once with de-ionized water in the solvent blend, which was taken out during the second treatment.

4.3.2.3.1 First Treatment (2.1%)

This treatment was conducted prior to the decision of taking the de-ionized water out of the solvent mixture. **Table 12** shows the target and the actual measurements of the chemicals used as solvents as well as surfactant measurements.

Table 12. GB2-3 first treatment target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	293.26
38.4	38.44	2	1+ 63.99% Propylene glycol	331.70
17.4	17.39	3	2+ 28.95% Isopropanol	349.09
3	2.98	4	3+ 4.96% DI water	352.07
1.2	1.26	5	4+ 2.10% SA-17	353.33

During this treatment, the oven thermal stability was reached at 180^{o} F, after 9 hours. After that, treatment was injected for an hour and a half until 5 PV was collected at the outlet. The outlet valve was closed to age the core at high temperate for 12 hours. **Table 13** shows that 20 cc of treatment was collected after air flowing.

Permeability was reduced by 18% after this treatment, due to the amount of de-ionized water in the solvent blend as shown in **Fig. 41**.

Table 13. BG2-3 first treatment data

Date	2/23/2017
Confined Pressure, psi	1000
Oven Temperature, F	180
Oven Temperature, C	82.22
Pumping Rate, mL/min	2
Pumping Time, min	90
Collected Chemical Volume before aging, cc	25
Collected Chemical Volume after Air flowing for 5 min with closed valve followed by 60 mins open valve, cc	20
Remained Chemical Volume in Accumulator, cc	0
Core Weight After Treatment, g	52.95
Core Dry Weight, g	50.23

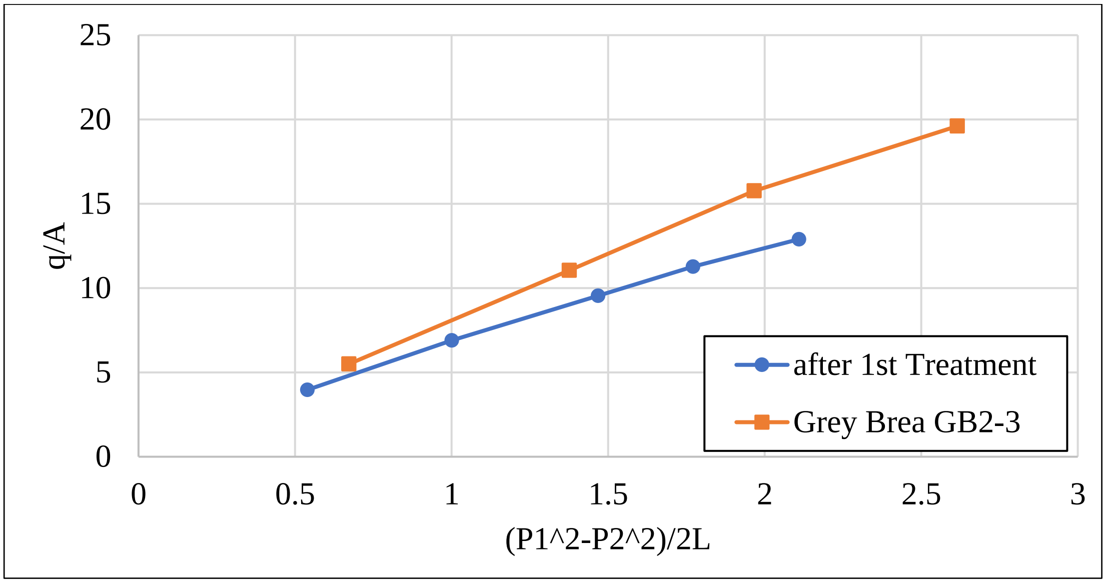


Figure 41. GB2-3 “18%” permeability reduction after the first treatment

4.3.2.3.2 Second Treatment (2.1%)

It took 10 hours to reach thermal stability at 181° F. During the second treatment, de-ionized water was injected before the treatment, instead of blending it with the solvent chemicals, and the planned chemical solvents ratio was maintained as 70/30 from this treatment onwards as shown in **Table. 14**

Table 14. GB2-3 second treatment target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	293.24
41.16	41.19	2	1+ 70.05% Propylene glycol of Solution	334.43
17.64	17.61	3	2+ 29.95% Isopropanol of Solution	352.04
1.2	1.26	4	3+ 2.10% SA-17	353.3

The treatment was injected for 90 minutes before 5 PV was collected at the outlet. Then the outlet valve was closed and the core was aged at high temperate for 15 hours and a half before air flowed. After flowing air, 14 cc of treatment was collected as shown in **Table 15**.

A 3% decline of the permeability was recorded after this treatment compared to the first treatment as shown in **Fig. 42**.

Also, a normal decane imbibition comparison between GB2-3 before and after the second treatment was conducted as shown in **Fig. 43**. The recovery of GB2-3 after the second treatment started right below the recovery of GB2-3 before treatment, but there was no change in imbibition rate observed.

Table 15. BG2-3 second treatment data

Date	3/4/2017
Confined Pressure, psi	1150
Oven Temperature, F	181.40
Oven Temperature, C	83.00
Treatment Stirring Time, min	1.00
Treatment Settling after Stirring Time, min	8.00
DI Water Pumping Rate, mL/min	2
Treatment Pumping Rate, mL/min	2
DI Water Pumping Time, min	17.1833
Treatment Pumping Time, min	90
Total Prepared Treatment Volume, cc	100
Collected DI Water and Chemical Volume before aging, cc	40
DI Water Volume, cc	14
Collected Chemical Volume before aging, cc	26
Collected Chemical Volume after Air flowing for 5 min with closed valve followed by 90 mins open valve, cc	14
Remained Chemical Volume in Accumulator, cc	0
Core Weight After Treatment, g	52.166
Core Dry Hot Weight, g	50.17

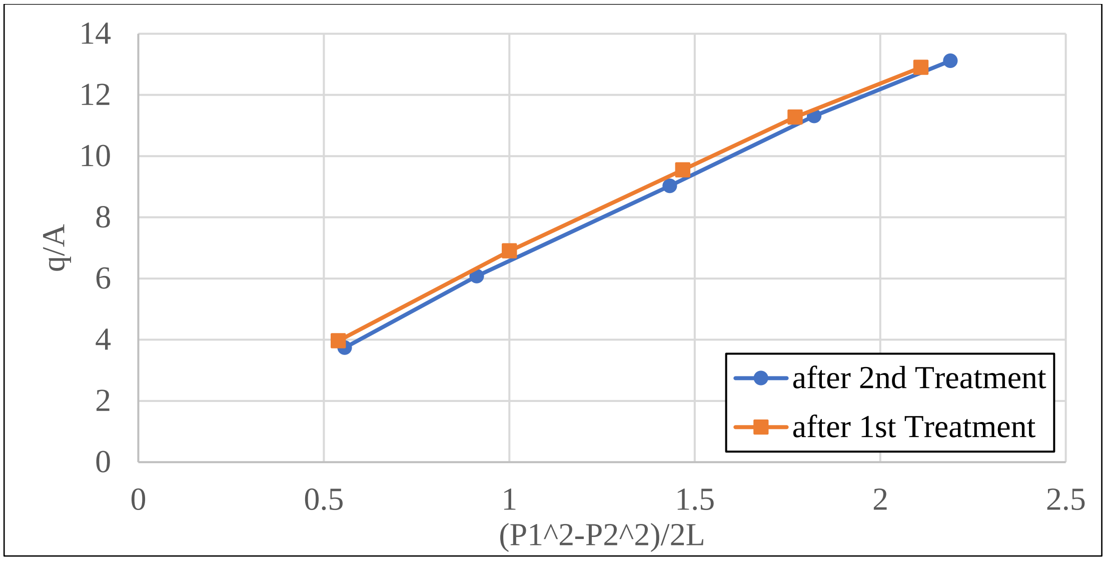


Figure 42. GB2-3 “3%” permeability reduction after the second treatment

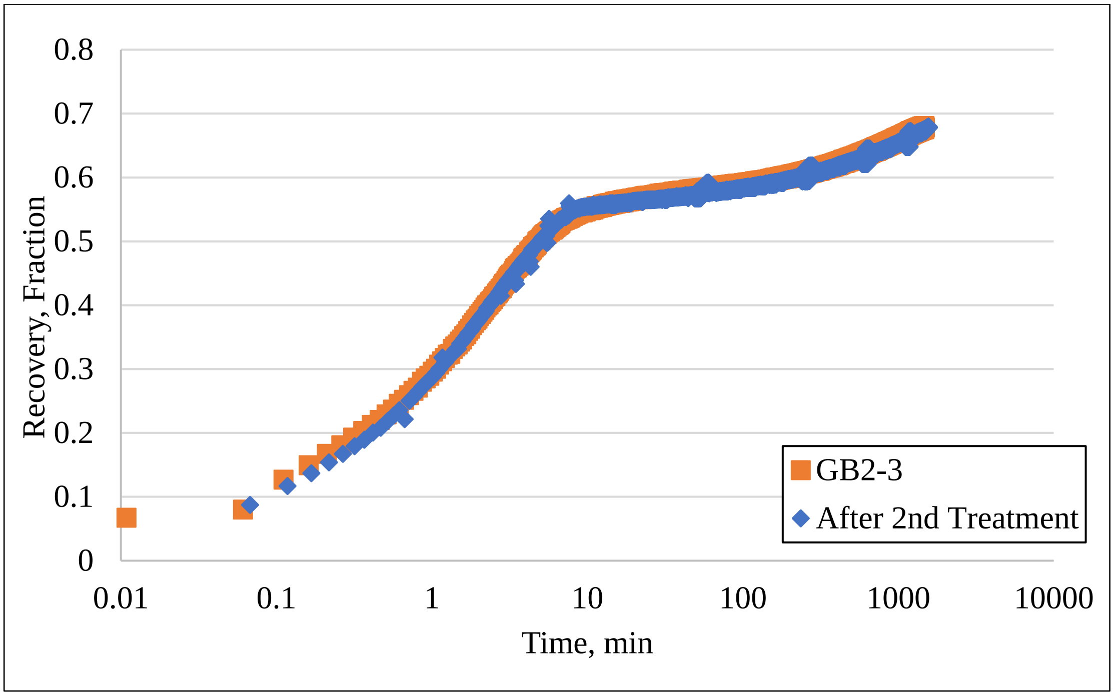


Figure 43. GB2-3 decane spontaneous imbibition before and after second treatment

4.3.2.4 BGB1-1 (4.03%)

Right before this treatment, slide glass experiment was conducted and a decision was made to switch to 70/30 blend of 2-butoxyethanol/ethanol solvent, from propylene glycol/isopropanol as discussed in **section 4.3.1.**

This treatment was the last treatment attempt at high temperature and during which another solvent blend was used as shown in **Table 16**.

After thermal stability, first de-ionized water was injected to the core followed by the injection of the treatment mixture. Once 29 cc of treatment is collected at the outlet, the core was aged at a high temperature for 12 hours before air was flowing and another 20 cc was collected as shown in **Table 17**.

Table 16. BGB1-1 actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	293.24
40.32	40.33	2	1+ 69.99% 2-butoxyethanol of Solution	333.57
17.28	17.29	3	2+ 30.01% ethanol of Solution	350.86
2.4	2.42	4	3+ 4.03 SA-17	353.28

This treatment reduced the permeability of the core by 10% as shown in **Fig. 44**. It also did not enhance the contact angle behavior, and the treatment was not effective.

Table 17. BGB1-1 treatment data

Date	3/18/2017
Confined Pressure, psi	1450-1550
Oven Temperature, F	181.40
Oven Temperature, C	83.00
Treatment Stirring Time, min	1.00
Treatment Settling after Stirring Time, min	33.00
DI Water Pumping Rate, mL/min	2
Treatment Pumping Rate, mL/min	2
DI Water Pumping Time, min	13.67
Treatment Pumping Time, min	31.7167
Total Prepared Treatment Volume, cc	100
Collected DI Water and Chemical Volume before aging, cc	48
DI Water Volume, cc	19
Collected Chemical Volume before aging, cc	29
Collected Chemical Volume after Air flowing for **8** min with closed valve followed by **60** mins open valve, cc	20
Remained Chemical Volume in Accumulator, cc	0
Core Weight After Treatment, g	52.289
Core Dry Hot Weight, g	52.058

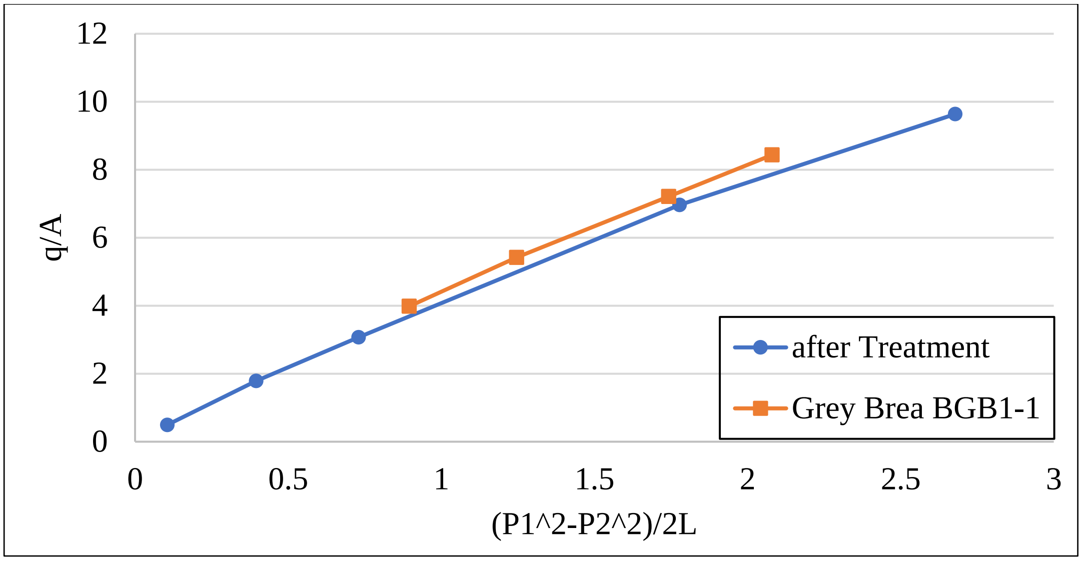


Figure 44. GB1-1 “10%” permeability reduction after treatment

A summary of all the high temperature treatments is shown in **Table. 18**

4.3.3 Low Temperature Treatments

All the high temperature treatment attempts did not give a good indication when testing them using normal decane imbibition and contact angle methods. For these reason, several percentages of the same surfactant (2, 4 and 8%) were tested using the same ratio of the same solvent blend of 2-butoxyethanol/ethanol under room temperature. Also during this approach, there was no air injection after aging the cores for 12 hours.

Table 18. Summary of high temperature treatment data

*Core Sample	Length, in	Porosity, %	Permeability, mD	Surfactant Percentage, %	Solvent
GB2-1 (after Treatment)	1.83	20.9	93	1.28%	Propylene glycol /Isopropanol /DI water
GB2-2 (after Treatment)	1.87	22.6	118	1.92%	Propylene glycol /Isopropanol /DI water
GB2-2 (after 2nd Treatment)	1.87	20.8	109	4.21%	Propylene glycol/Isopropanol
GB2-3 (after 1st Treatment)	1.87	21.7	113	2.10%	Propylene glycol/Isopropanol /DI water
GB2-3 (after 2nd Treatment)	1.87	21.4	110	2.10%	Propylene glycol/Isopropanol
BGB1-1 (after 1st treatment)	1.94	20.4	66	4.03%	2-butoxyethanol /ethanol

*All cores have a 1 inch diameter

4.3.3.1 BGB1-2 (4.03%)

This core was the first core to be tested at room temperature using the surfactant weight percentage of 4% based on the result of the normal decane imbibition of the BGB1-1. **Table 19** shows the weight percentages of the solvent and the surfactant used for this treatment.

Table 19. BGB1-2 target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	293.24
40.32	40.34	2	1+ 70.02% 2-butoxyethanol of Solution	333.58
17.28	17.27	3	2+ 29.98% ethanol of Solution	350.85
2.4	2.42	4	3+ 4.03% SA-17	353.27

First, de-ionized water was injected into the core at a rate of 2 cc/min then the treatment mixture was injected at the same rate for about 34 minutes as shown in **Table 20.**

After the treatment, permeability measurement showed a reduction of 15% compared to the permeability before treatment as shown in **Fig. 45**. Also, normal-decane imbibition was conducted on this core before and after the treatment to examine the effect of the treatment on the decane imbibition. **Fig. 46** shows the optimum decane imbibition where the recovery was low at the beginning then it started to increase and slowed down again as decane was prevented to imbibe deeper into the core.

Table 20. BGB1-2 treatment data

Date	3/21/2017
Confined Pressure, psi	
Room Temperature, F	77.00
Room Temperature, C	25.00
Treatment Stirring Time, min	1.00
Treatment Settling after Stirring Time, min	53.00
DI Water Pumping Rate, mL/min	2
Treatment Pumping Rate, mL/min	2
DI Water Pumping Time, min	11.687
Treatment Pumping Time, min	33.9
Total Prepared Treatment Volume, cc	100
Collected DI Water and Chemical Volume before aging, cc	40
DI Water Volume, cc	15
Collected Chemical Volume before aging, cc	25
Collected Chemical Volume after Air flowing for **8** min with closed valve followed by **60** mins open valve, cc	No Air Flow
Remained Chemical Volume in Accumulator, cc	4
Core Weight After Treatment, g	49.91
Core Dry Hot Weight, g	46.54

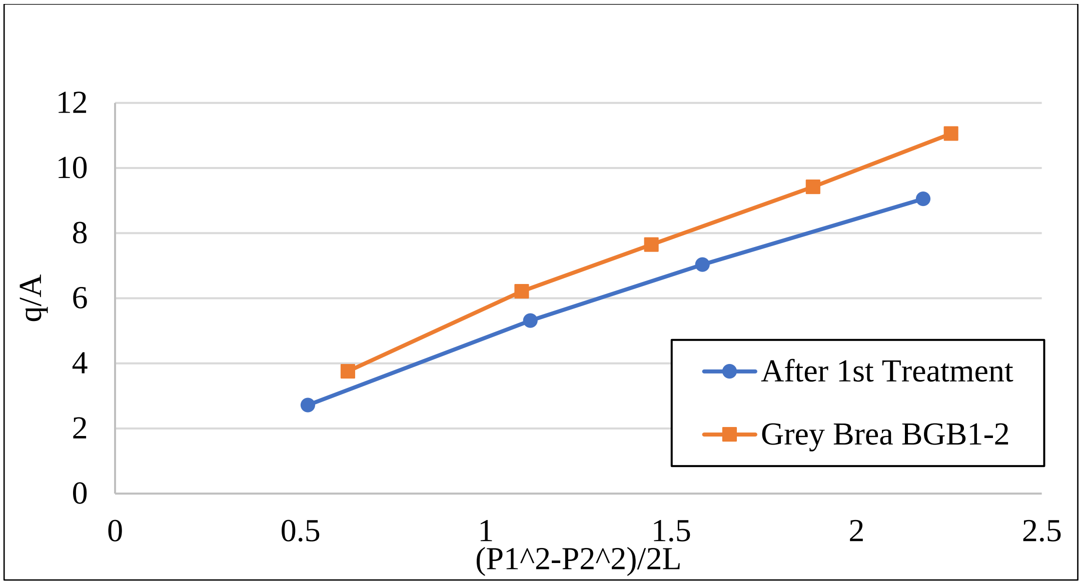


Figure 45. BGB1-2 “15%” permeability reduction after treatment

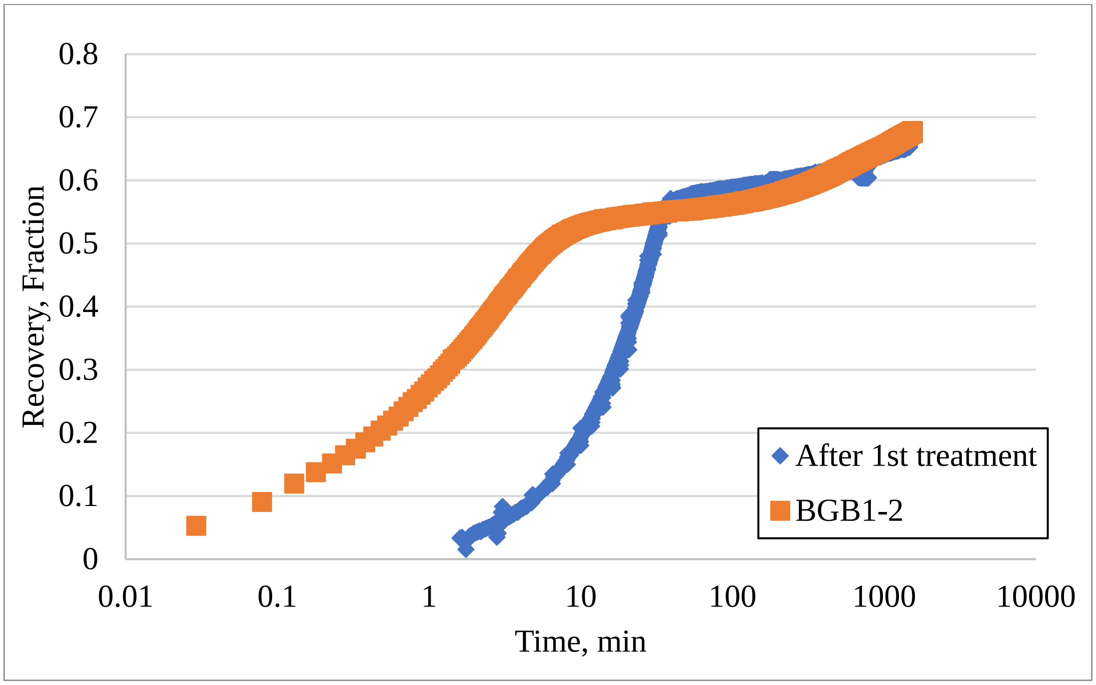


Figure 46. BGB1-2 decane spontaneous imbibition before and after treatment

4.3.3.2 BGB5-1-2 (8.07%)

After the good result of the BGB1-2, it was decided to treat the core with 8% at room temperature and study the result. All parameters were kept the same as the previous treatment expect the surfactant weight percentage increased to 8% as shown in **Table 21**.

Table 21. BGB5-1-2 target and actual chemical weight percentages

Each “Target” Chemical Weight, g	Each “Actual” Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	185.88
38.64	38.67	2	1+ 70.00% 2-butoxyethanol of Solution	224.55
16.56	16.57	3	2+ 30.00% ethanol of Solution	241.12
4.8	4.85	4	3+ 8.07% of SA-17	245.97

Permeability measurement was conducted before and after the treatment, showing no decrease even though they have the same slope despite early points as shown in **Fig. 47**. Normal decane imbibition shows a lower recovery than 4% treatment but the recovery curve was not able to exceed the untreated core’s recovery as seen with the 4% treatment (**Fig. 48**)

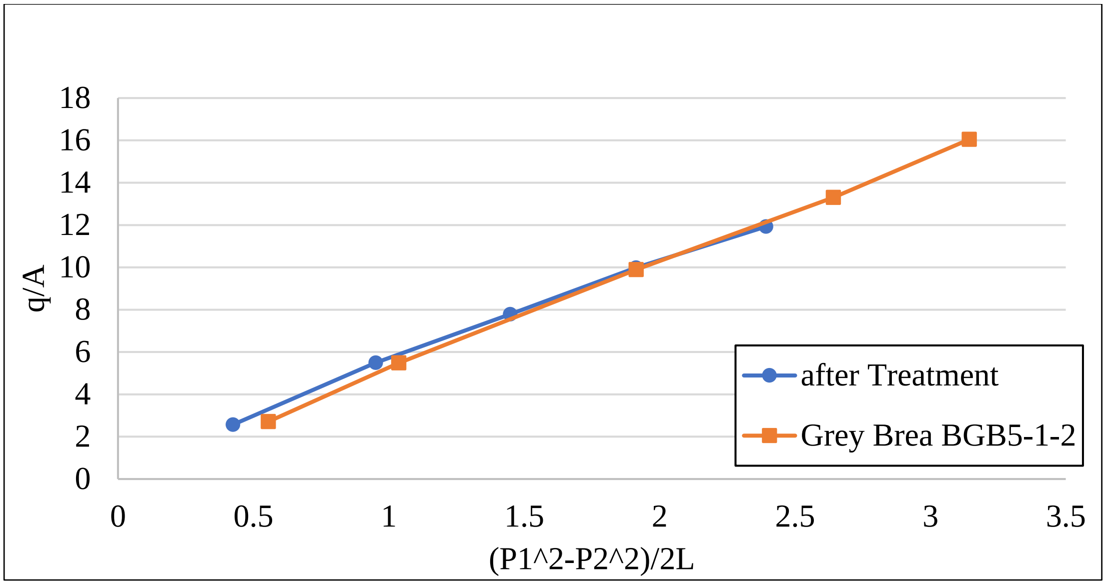


Figure 47. BGB5-1-2 permeability before and after treatment

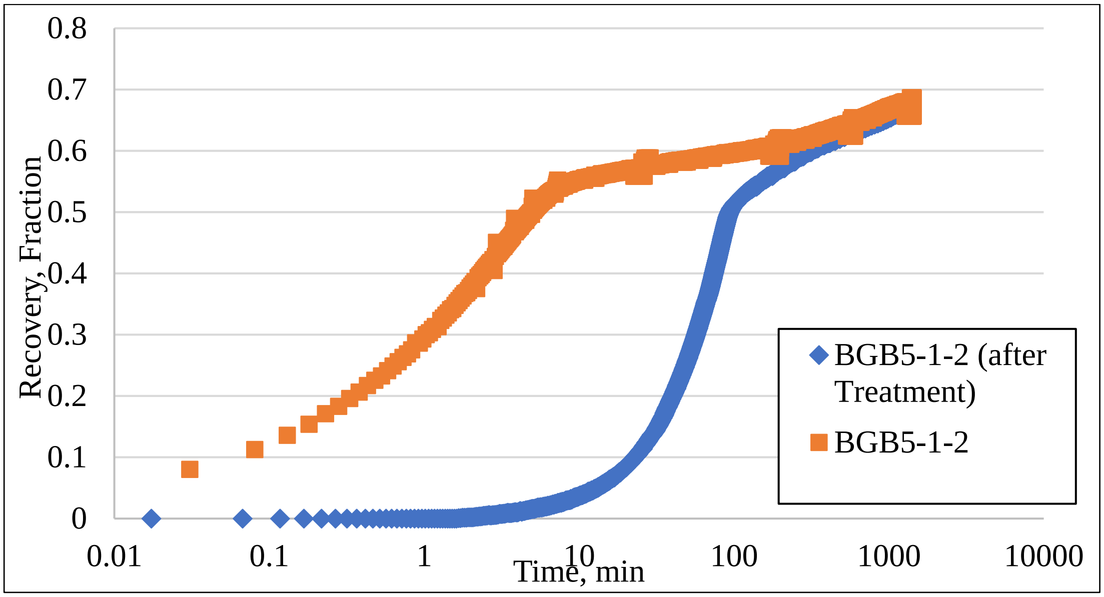


Figure 48. BGB5-1-2 decane spontaneous imbibition before and after treatment

4.3.3.3 BGB5-1-1 (2.02%)

Treatment at 2% was done to investigate the lower weight percentage of the surfactant at room temperature. Before conducting 2% treatment on core BGB5-1-1, it was conducted on BGB5-3. Although, the contact angle after treatment was giving good angles for both de-ionized water and normal decane (**Fig.49**), the spontaneous imbibition after treatment showed a recovery higher than the untreated core as shown in **Fig.50.** Another core, BGB5-1-1, was used to reproduce the data and ensure the results.

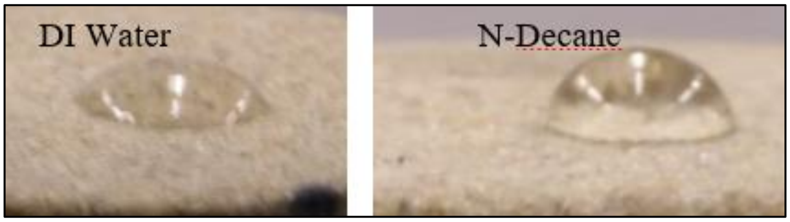


Figure 49. BGB5-3 contact angle after 2% treatment

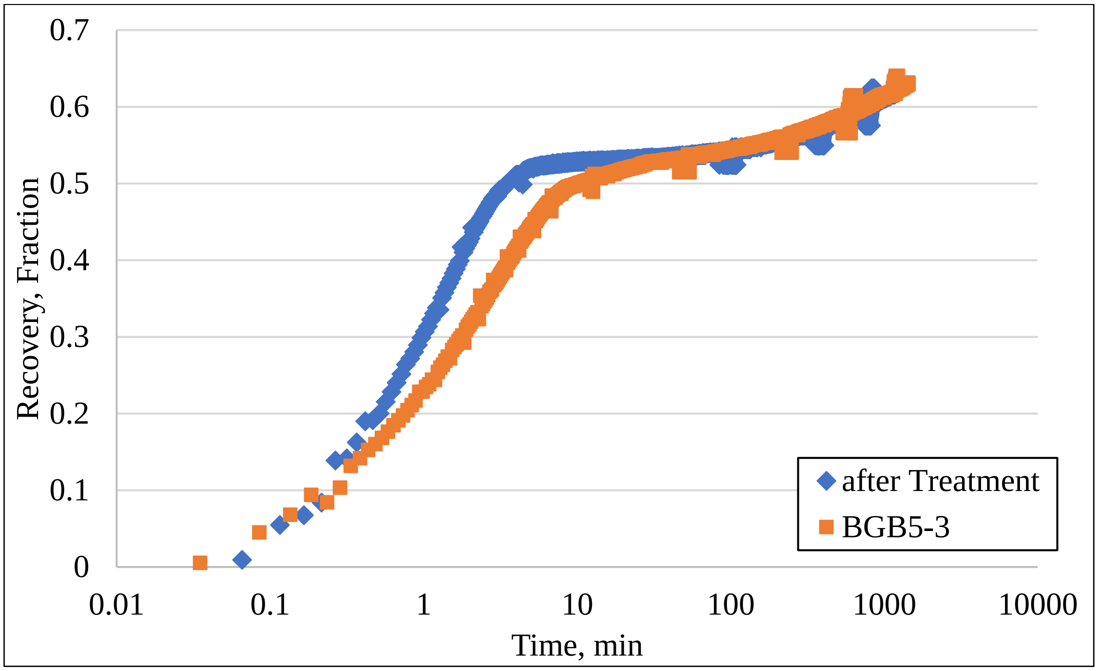


Figure 50. BGB5-3 decane spontaneous imbibition before and after treatment

Table 22 shows the target and actual weight percentages used for both surfactant and solvent blend of this treatment.

Table 22. BGB5-1-1 target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	185.83
41.16	41.23	2	1+ 70.11% 2-butoxyethanol of Solution	227.06
17.64	17.58	3	2+ 29.89% ethanol of Solution	244.64
1.2	1.21	4	3+ 2.02% of SA-17	245.85

A decline of 23% was observed after the treatment as shown in **Fig. 51**. Also, a normal decane imbibition was conducted before and after treatment as shown in **Fig. 52**. The recovery of the treated core started lower than the untreated core then increased for a while before it declined again below the recovery of the untreated core.

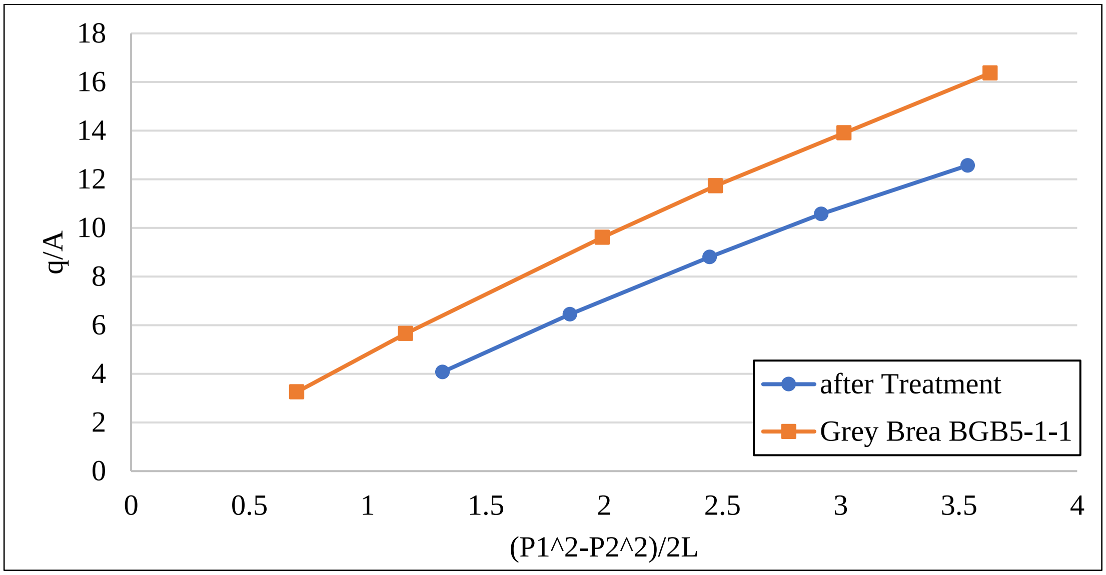


Figure 51. BGB5-1-1 "23%" permeability reduction after treatment

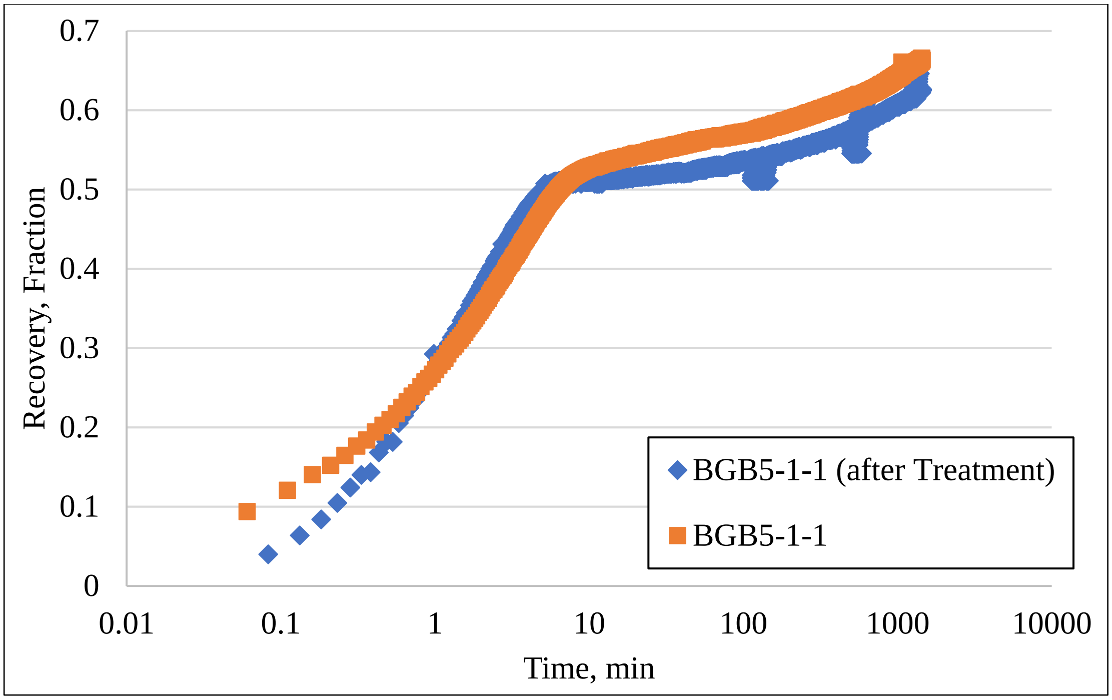


Figure 52. BGB5-1-1 decane spontaneous imbibition before and after treatment

4.3.3.4 BGB4 (4.04%)

After the successful low temperature attempts using screening cores (short cores), this 6-inche core was treated with 4% of surfactant and similar solvent blend to conduct a relative permeability experiment afterwards. **Table 23** shows the target and actual weight percentages used for both surfactant and solvent blend of this treatment.

Table 23. BGB4 target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	171.72
67.2	67.22	2	1+ 70.03% 2-butoxyethanol of Solution	238.94
28.8	28.77	3	2+ 29.97% ethanol of Solution	267.71
4	4.04	4	3+ 4.04% of SA-17	271.75

After this treatment, permeability declined by 29% as shown in **Fig. 53**. Also, **Fig. 54** shows the normal decane imbibition comparison before and after the treatment. It shows that the treatment is lowering the imbibition of the decane to the core by changing the wetting phase to gas-wet.

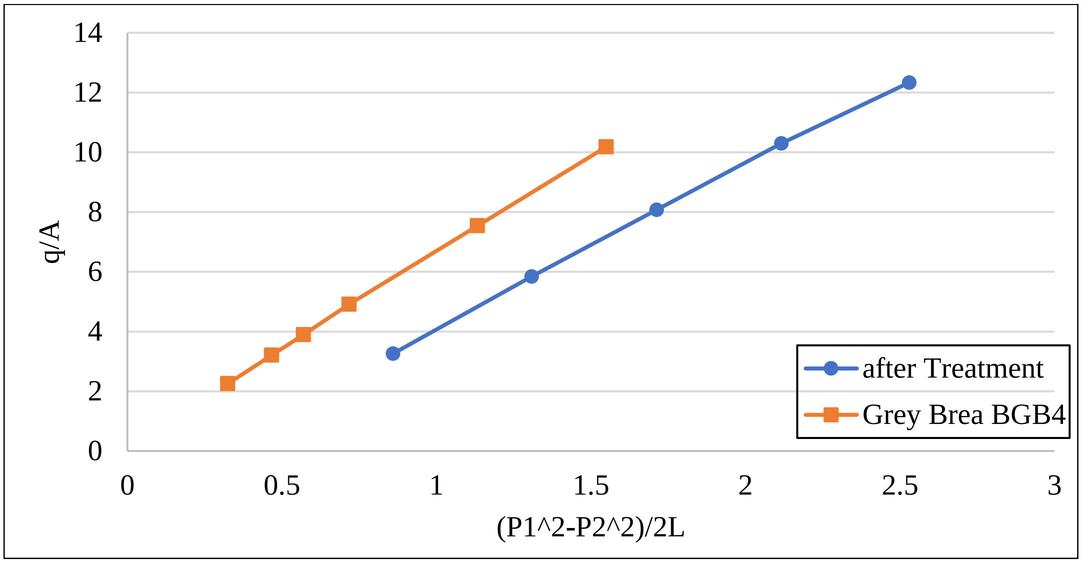


Figure 53. BGB4 “29%” permeability reduction after treatment

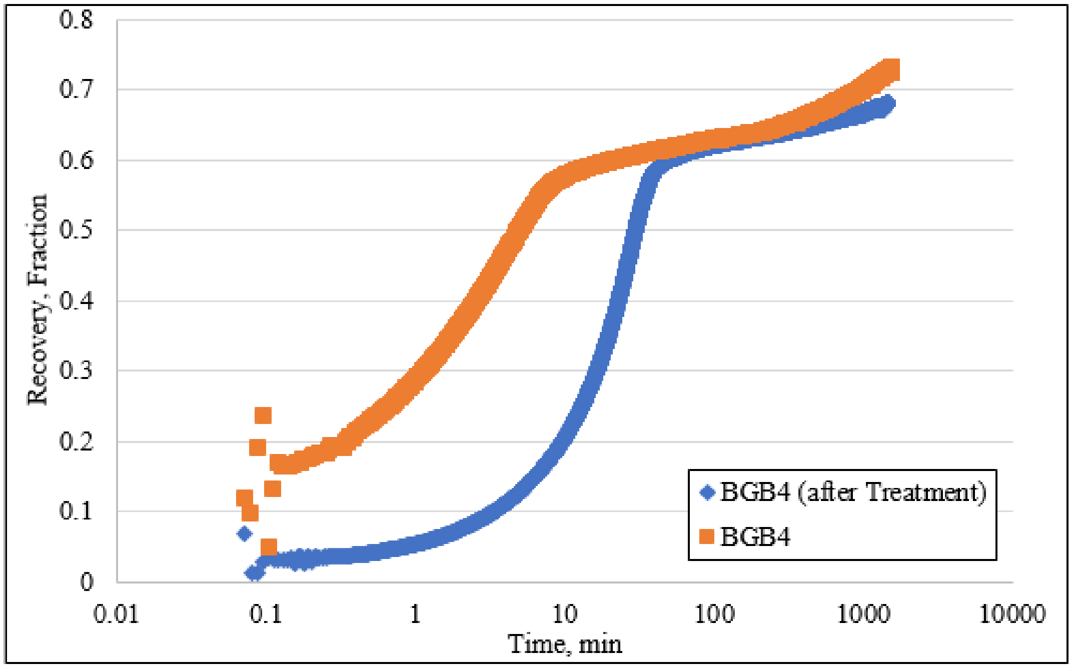


Figure 54. BGB4 decane spontaneous imbibition before and after treatment

4.3.3.5 BGB2 (8.12%)

After the relative permeability results of BGB4, an additional experiment was conducted to treat another long core with 8% and investigate the relative permeability curve after the treatment. **Table 24** shows the target and actual weight percentages used for both surfactant and solvent blend of this treatment.

Table 24. BGB8 target and actual chemical weight percentages

Each "Target" Chemical Weight, g	Each "Actual" Chemical Weight, g		**Actual Measurements, g**	
		1	Beaker	185.86
64.4	64.44	2	1+ 69.94% 2-butoxyethanol of Solution	250.30
27.6	27.70	3	2+ 30.06% ethanol of Solution	278
8	8.14	4	3+ 8.12% of SA-17	286.14

After this treatment, permeability declined by 13% as shown in **Fig. 55**. The normal decane imbibition comparison before and after the treatment shows that the treatment is slowing the imbibition of the decane to the core by changing the wetting phase to gas-wet up to certain point then it increased again as shown in **Fig. 56.**

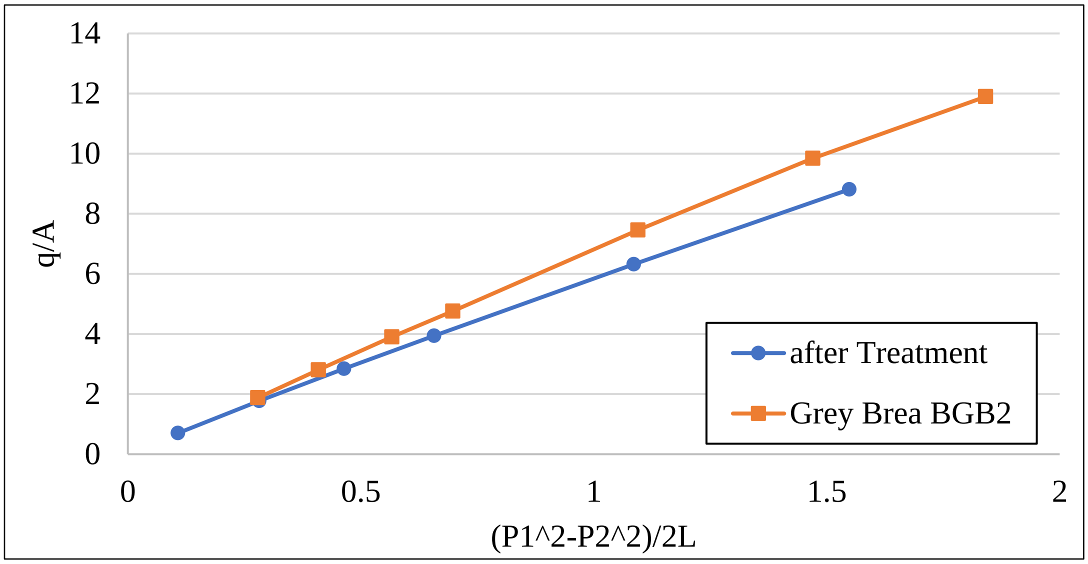


Figure 55. BGB2 “13%” permeability reduction after treatment

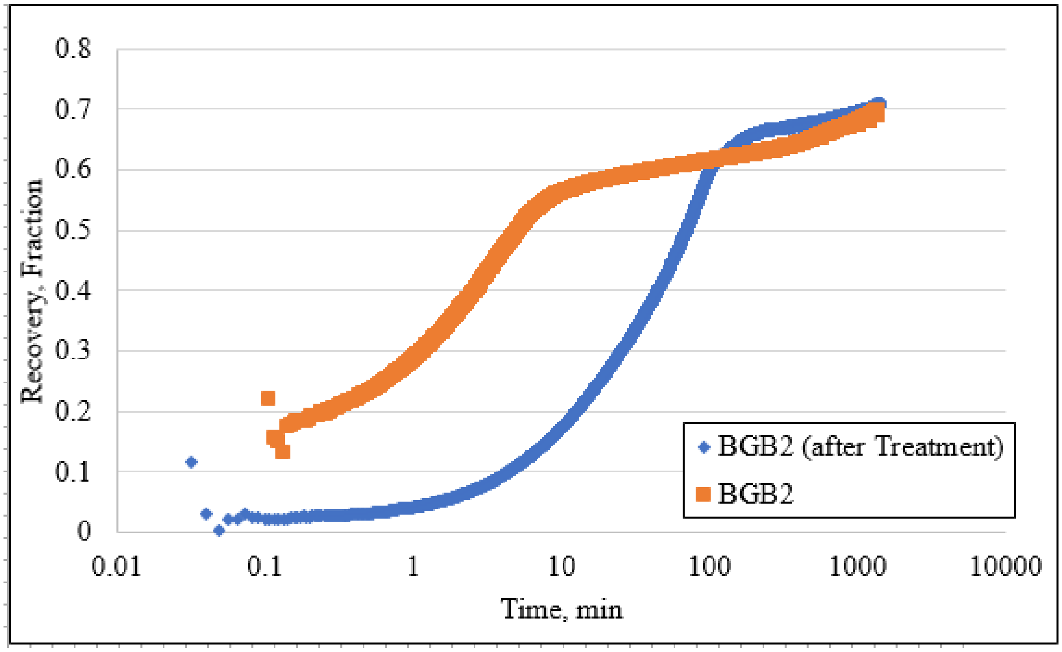


Figure 56. BGB2 decane spontaneous imbibition before and after treatment

Table 25 shows a summary of all the low temperature treatments

Table 25. Summary of low temperature treatment data

***Core Sample**	**Length, in**	**Porosity, %**	**Permeability, mD**	**Surfactant Percentage, %**	**Solvent**
BGB1-2 (after 1st Treatment)	1.76	20.5	77	4.03%	2-butoxyethanol /ethanol
BGB2 (after Treatment)	6.01	19.2	103	8.12%	2-butoxyethanol /ethanol
BGB4 (after Treatment)	5.95	19.6	85	4.04%	2-butoxyethanol /ethanol
BGB5-1-1 (after Treatment)	1.42	21.8	63	2.02%	2-butoxyethanol /ethanol
BGB5-1-2 (after Treatment)	1.55	19.5	92	8.07%	2-butoxyethanol /ethanol

*All cores have a 1 inch diameter

Fig. 57 shows a slope comparison of the early recovery of the decane imbibition before and after the treatment. It shows that all treatments were effective except the treatment with surfactant concentration of 2%. The slope comparison of the middle data shows that the treated decane imbibition slope increased as an indication of enhanced counter current flow characteristics as shown in **Fig. 58**.

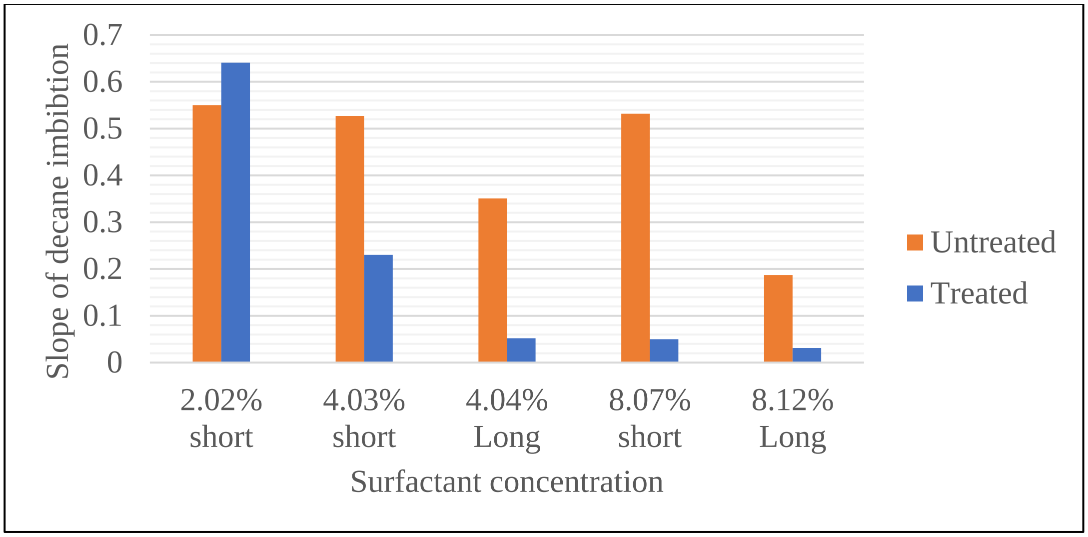


Figure 57. Slope comparison of early decane imbibition data

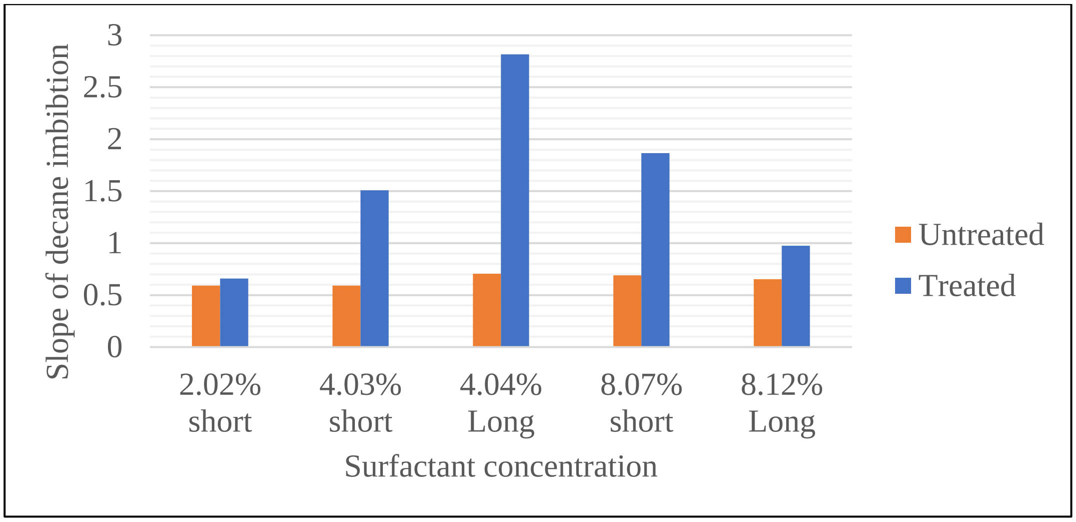


Figure 58. Slope comparison of middle decane imbibition data

4.4 Contact Angle

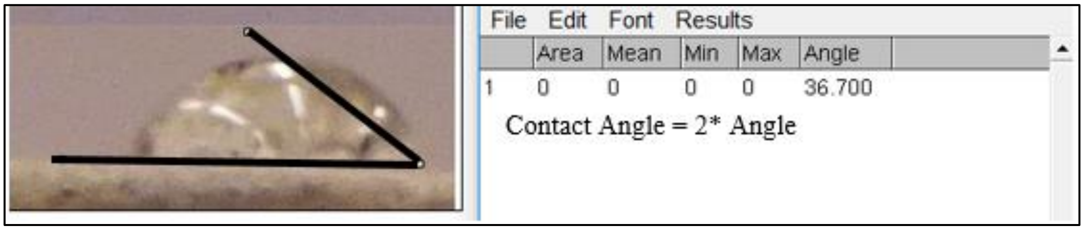
Maximum angle was measured using ImageJ software for cores treated at room temperature then contact angle was calculated by doubling the maximum angle as shown in **Table 26**.

Table 26. Contact angle data

Core Sample	Surfactant Percentage, %	Solvent	Decane	DI Water
BGB1-2 (after 1st Treatment)	4.03%	2-butoxyethanol /ethanol	73.4	71.1
BGB2 (after Treatment)	8.12%	2-butoxyethanol /ethanol	60.3	31.7
BGB4 (after Treatment)	4.04%	2-butoxyethanol /ethanol	0.0	33.7
BGB5-1-1 (after Treatment)	2.02%	2-butoxyethanol /ethanol	0.0	30.4
BGB5-1-2 (after Treatment)	8.07%	2-butoxyethanol /ethanol	46.7	61.1

A decane-air contact angle of 60 and 73 degrees formed after treating the cores with 8% and 4%, respectively as shown in **Fig. 59** and **Fig. 61**.

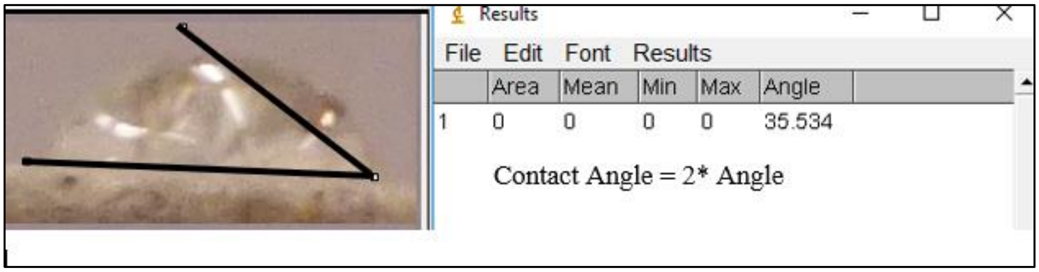
Fig. 60 and **Fig 62** show that the water-air contact angle for the same cores after treatment.



```
   Area  Mean  Min  Max  Angle
1  0     0     0    0    36.700
```

Contact Angle = 2* Angle

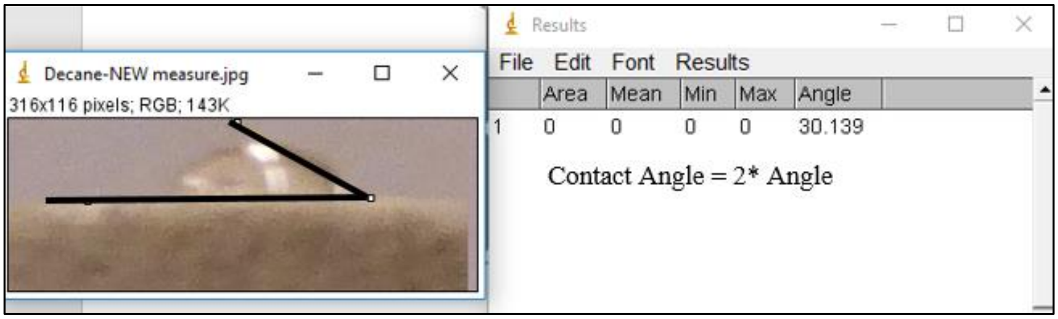
Figure 59. Air-decane contact angle after 4% treatment (BGB1-2)



	Area	Mean	Min	Max	Angle
1	0	0	0	0	35.534

Contact Angle = 2* Angle

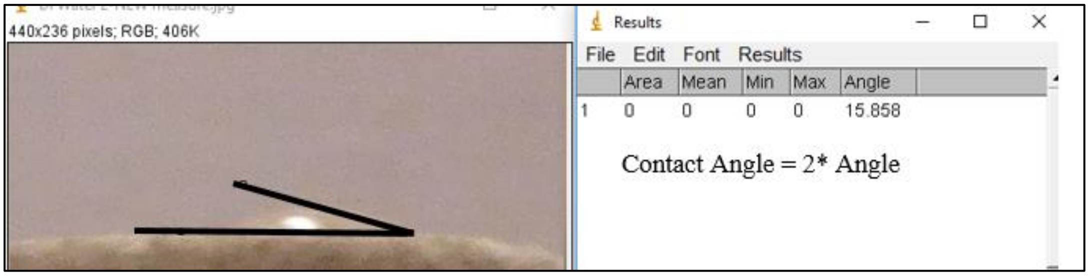
Figure 60. Air-water contact angle after 4% treatment (BGB1-2)



	Area	Mean	Min	Max	Angle
1	0	0	0	0	30.139

Contact Angle = 2* Angle

Figure 61. Air-decane contact angle after 8% treatment (BGB2)



	Area	Mean	Min	Max	Angle
1	0	0	0	0	15.858

Contact Angle = 2* Angle

Figure 62. Air-water contact angle after 8% treatment (BGB2)

4.5 Relative Permeability

This was the last experiment to evaluate the feasibility of the treatment and it was done on 6-inche cores. Three cores were used, the first core was untreated to form a base relative permeability curve and compare the relative permeability curves of the treated cores.

4.5.1 BGB3

The first core was untreated so its relative permeability curve will be used as a reference curve for the treated curves. BGB3 was used as the reference core, so it was saturated first with normal-decane as shown in **Table 27**.

Table 27. BGB3 saturation data

Core Sample	Dry Cold Weight, g	Wet Cold Weight, g	Pore Volume, cc	Vacuum Pressure, psi	Saturation, %
BGB3	161.85	172.59	15.35	-15	95.84

Then decane was injected to the core at 4 cc/min until the pressure stabilized to assure good saturation as shown in **Fig. 63**

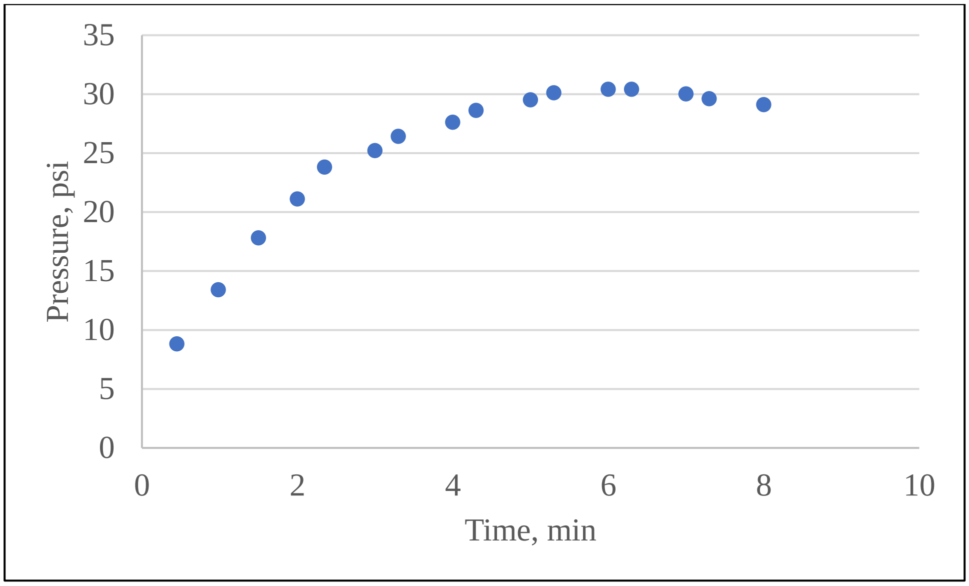


Figure 63. BGB3 decane injection plot

Nitrogen gas was injected until the rate stabilized and irreducible oil saturation was achieved as shown in **Fig. 64**.

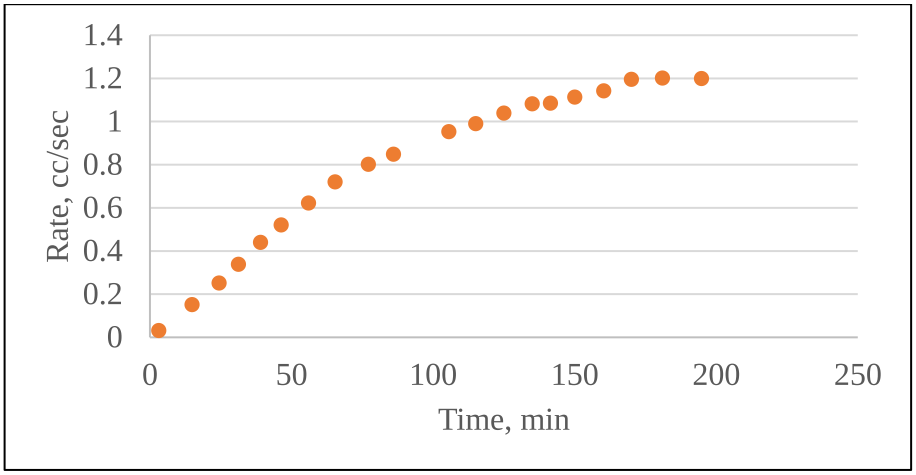


Figure 64. BGB3 nitrogen injection plot

Once Nitrogen rate stabilized, co-injection of both normal-decane and Nitrogen gas was conducted at different rates of normal-decane while keeping nitrogen at a constant pressure of 10 psi. Finally, normal-decane is injected at 0.2 cc/min to determine the oil relative permeability at the irreducible gas saturation. This would complete the relative permeability curve as shown in **Table 28** and **Fig. 65**

Table 28. BGB3 relative permeability data

Decane Rate	S_o	K_{ro}	K_{rg}
0	0.379246	0	0.61356
0.03	0.495251	0.017194	0.329491
0.05	0.530944	0.028953	0.145761
0.07	0.551468	0.040257	0.072915
0.1	0.590731	0.057314	0.045748
0.11	0.635348	0.058105	0.001073
0.13	0.678181	0.079947	0.001083
0.2	0.861111	0.295621	0

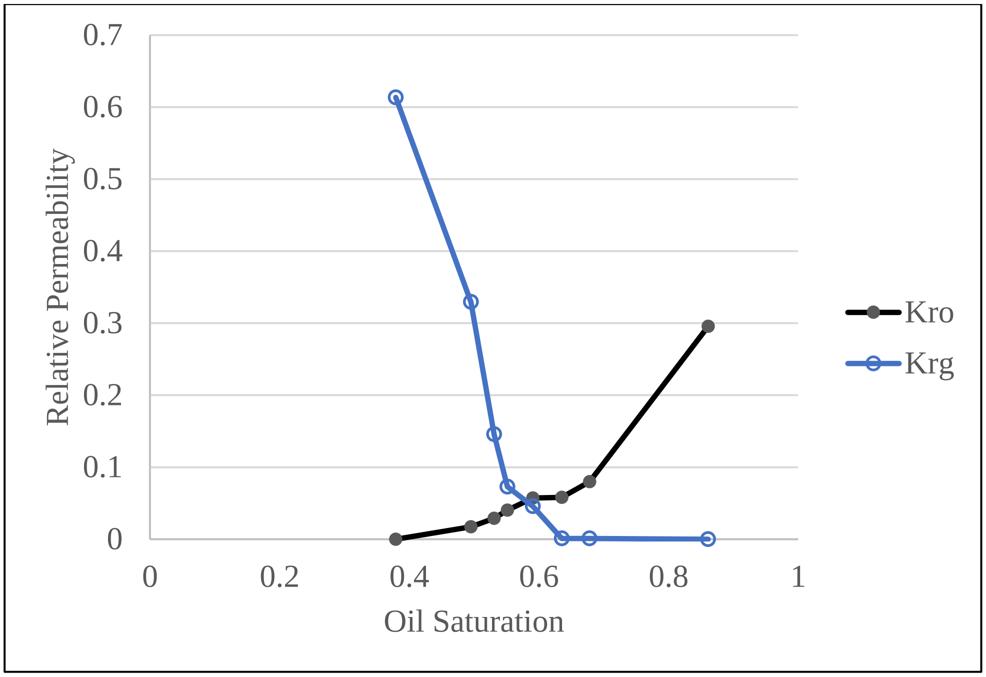


Figure 65. BGB3 relative permeability plot

4.5.2 BGB4 (4.04%)

After the treatment, the core was saturated with normal-decane as shown in **Table 29.**

Table 29. BGB4 saturation data

Core Sample	Dry Cold Weight, g	Wet Cold Weight, g	Pore Volume, cc	Vacuum Pressure, psi	Saturation, %
BGB4 (after Treatment)	161.92	172.33	14.94	-15	95.46

Normal-decane was injected at two different rates (2 cc/min and 4cc/min) until pressure stabilization occurred and saturation was assured as shown in **Fig. 66**

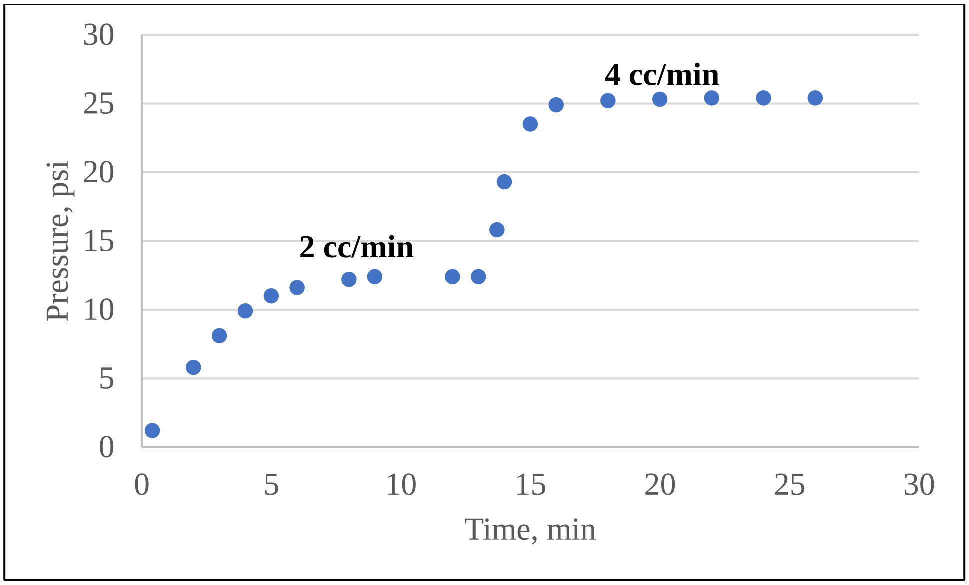


Figure 66. BGB4 decane injection plot

Then, Nitrogen gas was injected for 8 hours until the rate stabilized and irreducible oil saturation was attained as shown in **Fig. 67**.

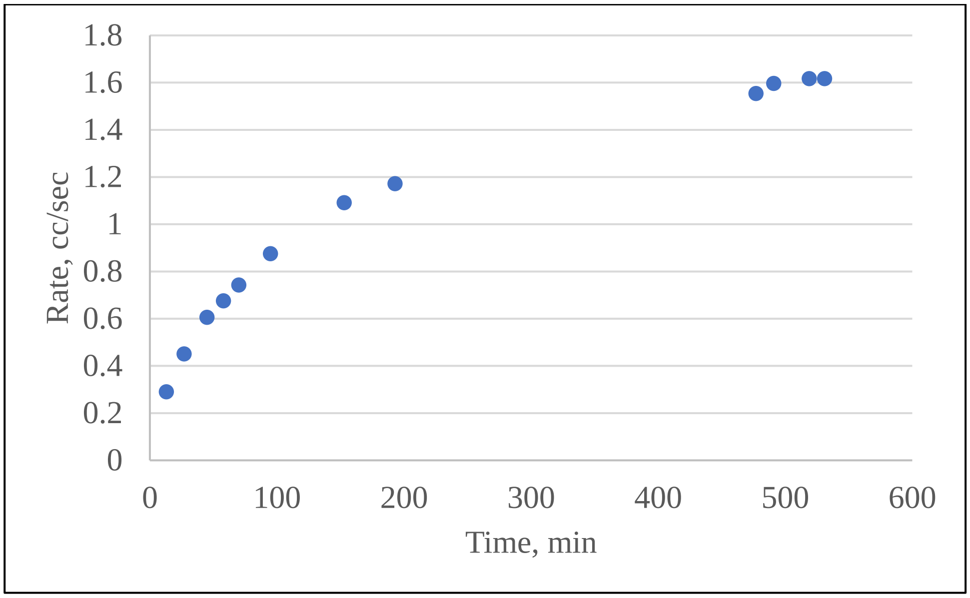


Figure 67. BGB4 nitrogen injection plot

Table 30 and **Fig. 68** show the relative permeability data for BGB4.

Table 30. BGB4 relative permeability data

Decane Rate	So	Kro	Krg
0	0.319102009	0	0.808693
0.03	0.49515829	0.019809	0.219921
0.05	0.536421481	0.029173	0.078242
0.1	0.6317853	0.054663	0.001035
0.2	0.832599496	0.302381	0

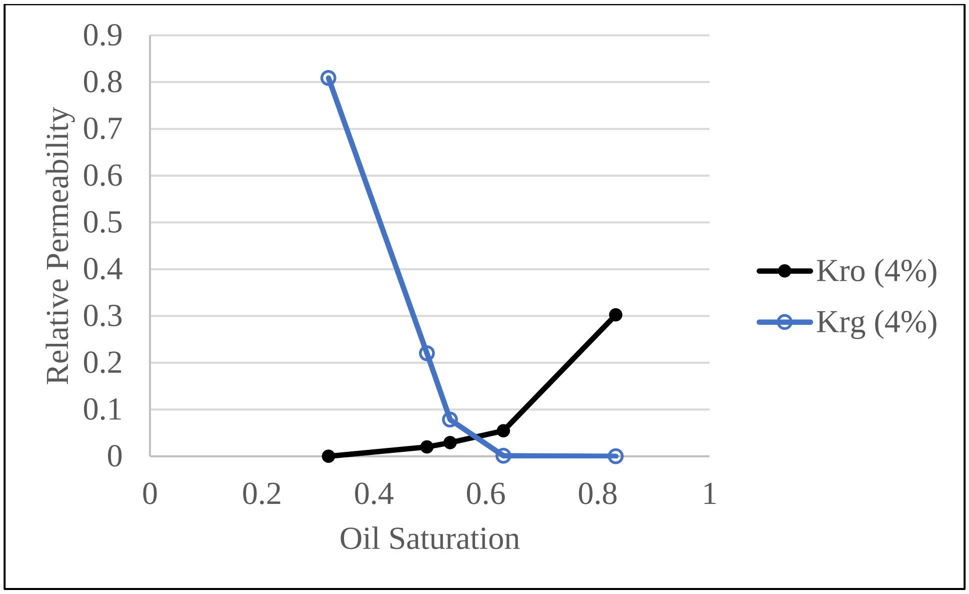


Figure 68. BGB4 relative permeability plot

Fig. 69 shows a comparison between BGB3 and BGB4 relative permeability curves; both curves have similar trend despite that BGB4 has higher end points.

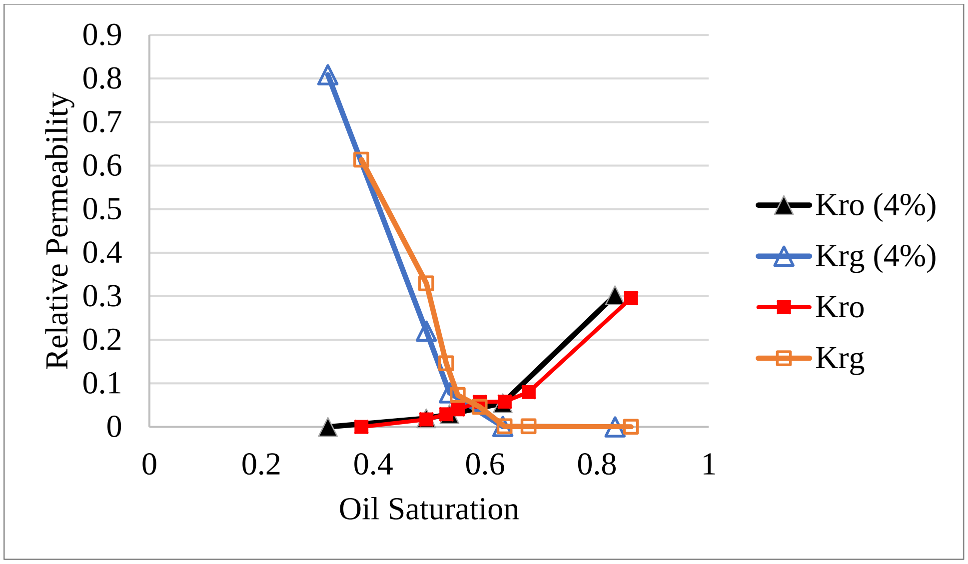


Figure 69. BGB3 (untreated) and BGB4 relative permeability plot

The existing relative permeability correlation for gas/liquid relative permeability curves do not match this observed behavior of the gas relative permeability. This needs to be investigated further.

4.5.3 BGB2 (8.12%)

The saturation of this core turned out a little lower than the previous two cores as shown in **Table. 31**.

Table 31. BGB2 saturation data

Core Sample	Dry Cold Weight, g	Wet Cold Weight, g	Pore Volume, cc	Vacuum Pressure, psi	Saturation, %
BGB2 (after Treatment)	162.75	172.88	14.74	-15	94.15

Once the core is saturated with normal-decane, decane was injected into the core at two rates (2 cc/min and 4 cc/min) until the pressure stabilized as shown in **Fig. 70**.

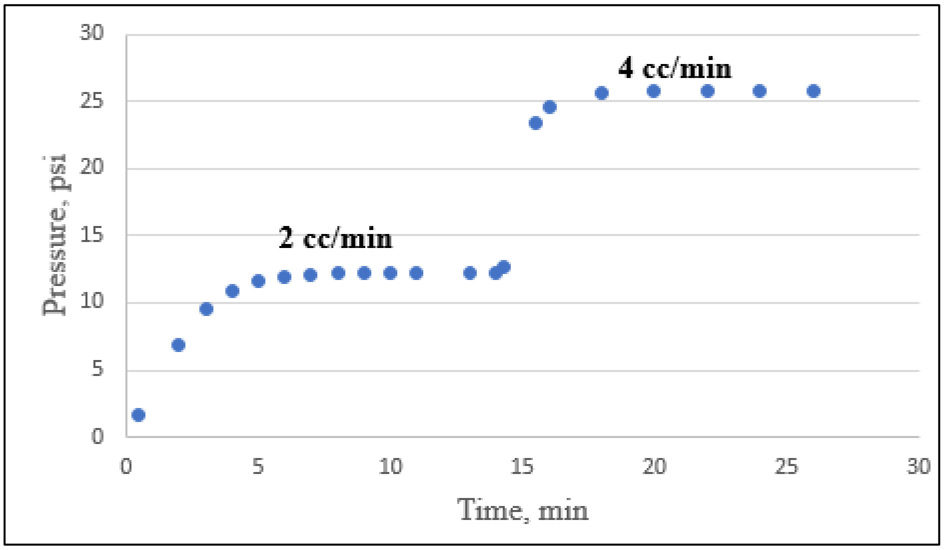


Figure 70. BGB2 decane injection plot

Then, Nitrogen gas was injected for 22 hours until the rate stabilized to reach the irreducible oil saturation as shown in **Fig. 71**.

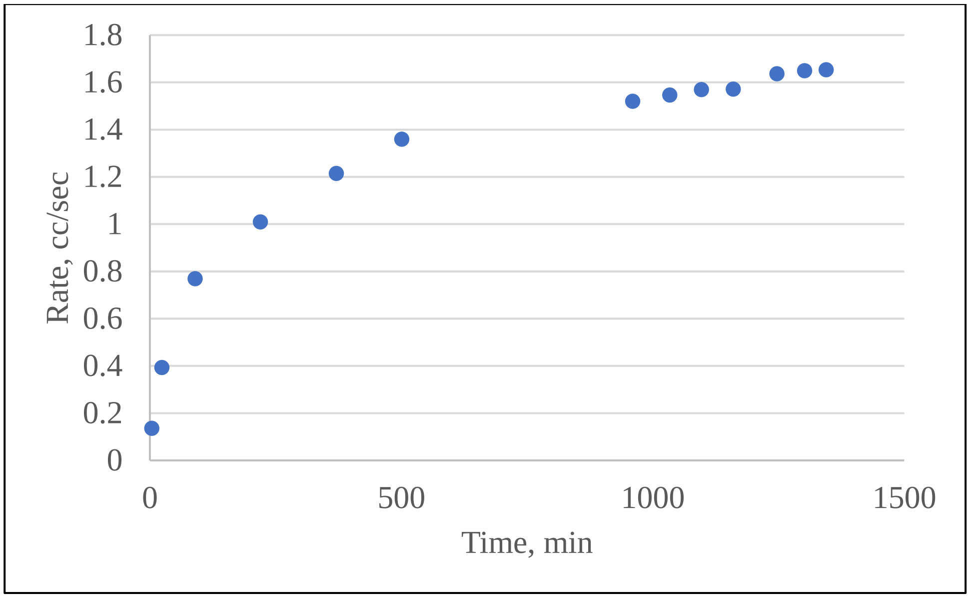


Figure 71. BGB2 nitrogen injection plot

Table 32 and **Fig. 72** show the relative permeability data for BGB2 that was treated with 8%.

Table 32. BGB2 relative permeability data

Decane Rate	So	Kro (8%)	Krg (8%)
0	0.222129	0	0.866465
0.03	0.470281	0.019084	0.288194
0.05	0.525116	0.032125	0.04582
0.07	0.545563	0.046128	0.000482
0.2	0.842044	0.584091	0

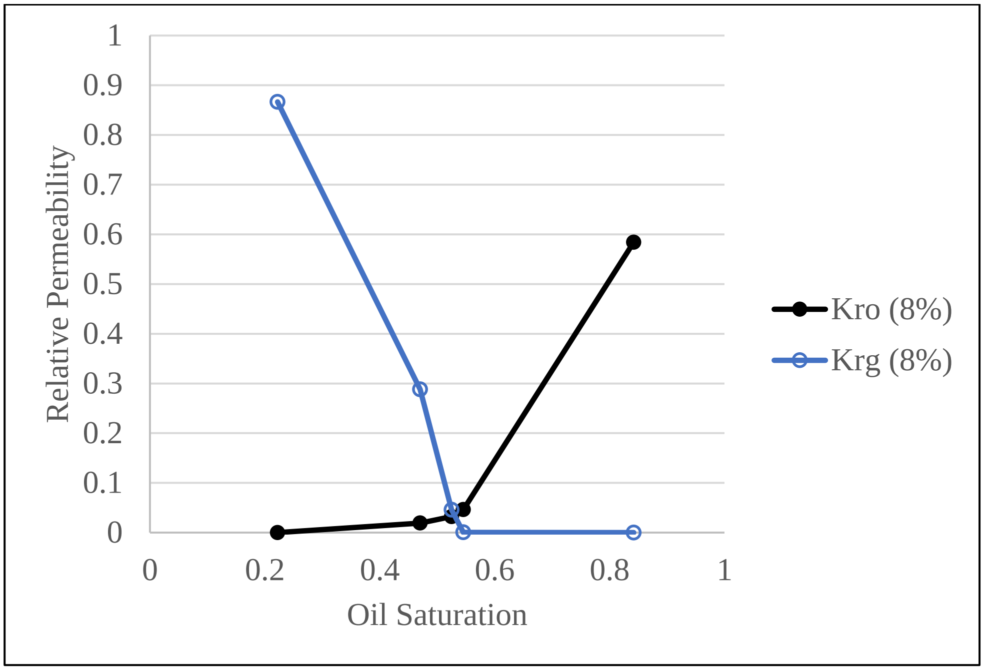


Figure 72. BGB2 relative permeability plot

Fig. 73 shows the relative permeability curve for BGB2 treated with 8% and BGB4 treated with 4% compared to the untreated core. It shows that BGB2 has a higher oil end point while BGB4 has a higher gas end point.

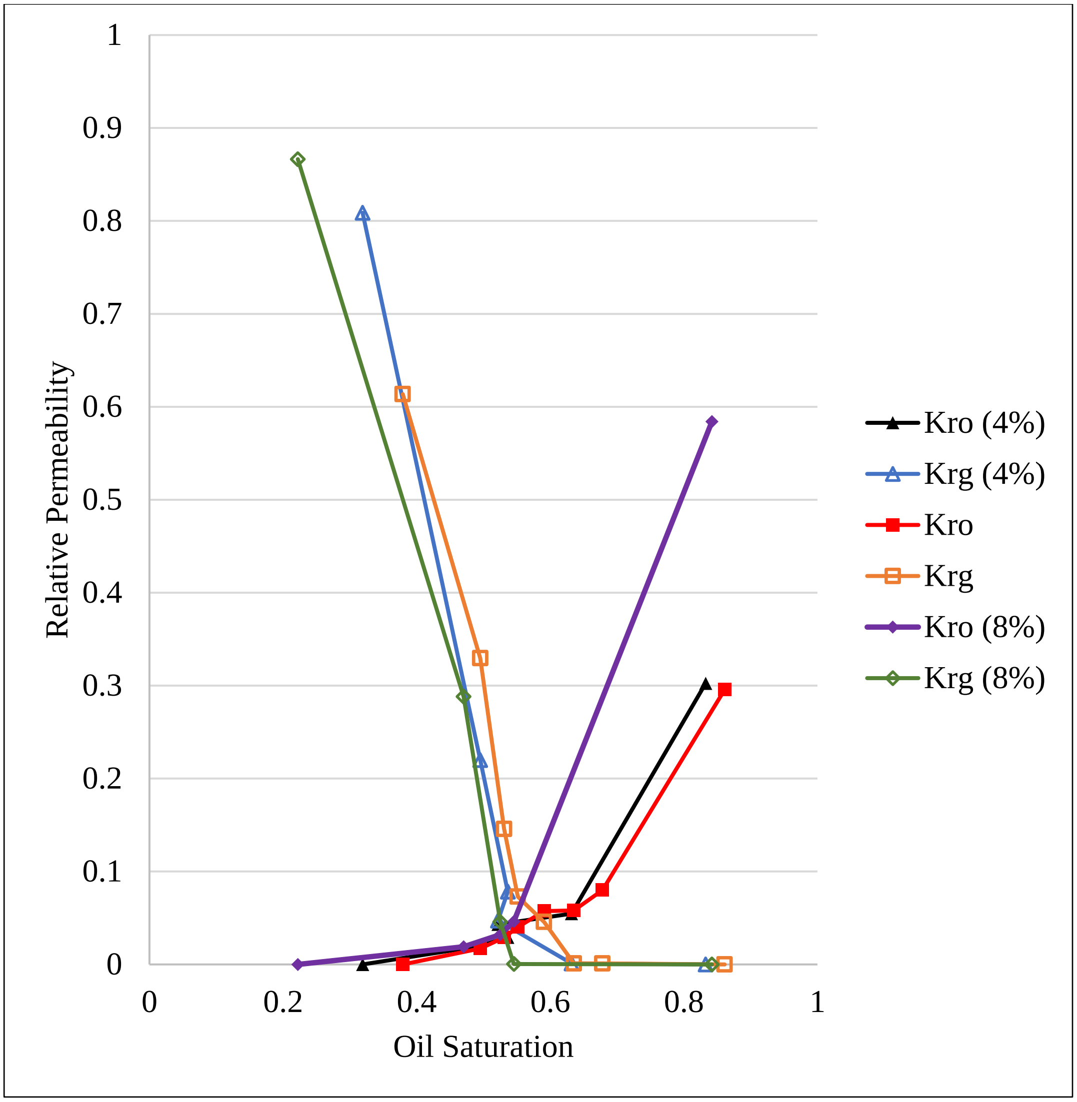


Figure 73. Comparison relative permeability plot

5. CONCLUSION

This study investigated the feasibility of surfactant SA-17 to alter the wettability of Grey Berea rocks by mixing it with two different combinations of solvent blends at two temperature ranges. The main goal was to observe whether it is possible to obtain various states of wettability as reflected in the relative permeability characteristics. The following is a list of the main conclusions from this work:

- It was shown for the first time that the change in wettability can result in an enhancement in the gas relative permeability end point value.
- The optimization in the relative permeability plot was shown to be reflected in a clear signature on the imbibition plot, with a slow initial imbibition rate.
- A sign of clay swelling was recorded through a unique signature of a hump in water imbibition which was initially puzzling.

6. RECOMMENDATIONS

After this study, several areas of research improvements are recommended as followed:

1- Conducting the treatment at intermediate temperatures between room temperature and 180^o F.

2- Conduct the treatment at different weight percentages of the active ingredient.

3- Study the effect of salinity on wettability alteration using SA-17 at different temperatures.

4- Study the effect of firing the cores in order to be able to perform water/gas and three phase experiments.

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