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Experimental Study of Residual Gas Saturation using both Spontaneous and Forced Imbibition Method, where IsoparL is the Wetting Phase

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Preface

This master thesis is intended primarily as a graduation thesis in the course TPG4950 at the Norwegian University of Science and Technology. The paper contains theoretical material on trapped gas. The thesis also includes detailed description of laboratory exercises suitable for finding trapped gas saturation. This master thesis was submitted 06. June 2012.

I would like to express my sincere gratitude to Professor Ole Torsæter Dept. of petroleum engineering and applied geophysics for his excellent help during this process.

I would also like to show my sincere appreciation to all the people working at Weatherford Laboratories, especially all who works in the lab for all their amazing help. They have thought me important knowledge about lab work and always done the best to help me when things did not go according to plan. Jules Reed has given me advice and inspiration throughout this project, and I would like express my sincere gratitude.

Statoil and Øyvind Bull managed to provide several cores that made it possible for me to execute the experiments, so I would like to thank them for making my thesis possible.

I would like to thank my fellow students at room 100. Your amazing support and companionship has made this process much easier.

Without these people I could not have been able to complete my master.

If anything can go wrong, it will
If there is a possibility of several things going wrong, the one that will cause the most damage will be the one to go wrong
If anything just cannot go wrong, it will anyway

- Capt. Ed Murphy

Abstract

Today most of the oil is produced. This has triggered a wider interest for gas reservoirs. To determine how much gas that can be recovered in a reservoir it is important with good knowledge of the trapped gas saturation. This includes getting more information about trapped gas which demands more research in this area. Trapped gas saturation is recognized as an important factor in the process of recovering gas.

In this project, literature has been studied and a lot of experimental work was done. Several papers have been read, and a basic knowledge of trapped gas, both what it is and how it can be determined, has been obtained. A main objective when reading was to gain knowledge about factors that affect the amount of trapped gas in a reservoir. In addition to reading about the theory, it has bee tested in the lab. The main purpose of the lab work was to see how rate change would affect the residual gas saturation, by using USS method. Spontaneous co-current imbibition experiments were also obtained.

Six cores; three Berea plugs and three cores from the northern sea were chosen for execution of the experiments. In total 3-4 USS experiments were executed for every core, where an important area of study should have been to figure out how different pressure differences would affect the results. In addition one spontaneous imbibition experiment where done for each core.

Normally water is used as the wetting phase. In this study IsoparL was chosen as the wetting fluid due to simplification factors in the lab. Previous studies of spontaneous imbibition experiments had shown good results when using IsoparL, so it was assumed that it could be used in USS experiments as well. It was discovered that IsoparL did not work well as the wetting fluid. By using this fluid, all the results obtained would be in the region of $\Delta P>0$. So the most important conclusion obtained from this study is that water should be used as the wetting fluid when studying S_{gr} by using USS method.

It was found that S_{gr} will decrease as rate increase when studying rates equal or larger than 4 ml/h with IsoparL as the wetting fluid.

Sammendrag

I dag er det meste av oljen produsert. Dette har skapt en bredere interesse for gassreservoarer. For å finne ut hvor mye gass som kan utvinnes i et reservoar er det viktig med god kjennskap til residuell gassmetning. Dette omfatter å få mer informasjon om residuell gassmetning som krever mer forskning på dette området. Fanget gass er anerkjent som en viktig faktor i prosessen med å utvinne gass.

I dette prosjektet har litteratur vært studert og mye eksperimentelt arbeid har blitt utført. Flere artikler har blitt lest, og en grunnleggende kunnskap om fanget gass, både hva det er og hvordan det kan fastslås, er innhentet. Et hovedmål ved lesingen var å få kunnskap om faktorer som påvirker mengden av fanget gass i et reservoar. I tillegg til å lese om teorien, ble det testet i laboratoriet. Hovedformålet med lab arbeidet var å se hvordan forandring i rate vil påvirke residuell gassmetning, ved å bruke USS metode. Spontan ”co-current” imbibering eksperimenter ble også utført. Seks kjerner, tre Berea plugger og tre plugger fra Nordsjøen ble valgt for gjennomføring av forsøkene. Det ble totalt utført 3-4 USS eksperimenter for hver kjerne, der et viktig område for studiet burde ha vært å finne ut hvordan ulike trykkforskjeller ville påvirke resultatene. I tillegg ble et spontant imbiberings eksperiment utført for hver kjerne.

Normalt er det vann som brukes som fuktende fase. I dette studiet ble IsoparL valgt som fuktende væske på grunn av forenklede forhold i laboratoriet. Tidligere studier av spontane imbiberings forsøk har vist gode resultater ved bruk IsoparL, så det ble antatt at den kunne brukes i USS eksperimenter også. Det ble oppdaget at IsoparL ikke fungerer bra som fuktende væske. Ved å bruke denne væsken, vil alle resultater være i regionen $\Delta P > 0$. Så den viktigste konklusjonen fra dette studiet er at vann bør brukes som fuktende væske når man studerer S_{gr} ved hjelp av USS metode.

Det ble funnet at S_{gr} vil minke når rate øker når man studerer rater som er like eller større enn 4 ml / t med IsoparL som fuktende væske.

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1 Introduction

When a company is producing from a gas reservoir, their main goal is to make as much money as possible. For this to be possible the amount of gas produced must cover all expenses. When initial gas in place (IGIP) has been established, it is important to determine how much of this gas that can be produced. This implies that it is important to determine trapped gas saturation.

When one immiscible fluid is displacing another, it is impossible to reduce the saturation of the displaced fluid to zero. At some stage the displaced fluid ceases to be continuous, and the flow decreases. At this point there will be a small fraction of the displaced fluid left in the reservoir which is called residual saturation. That is an important factor, when deciding the gas recovery in the reservoir.

Trapped gas saturation comprises both residual gas saturation (S_{gr}) and the unswept gas. S_{gr} is the bypassed gas while the unswept gas is the gas located in disconnected pores. It is always an optimal situation to have as low S_{gr} as possible, thus most of the gas in the reservoir has been produced.

In the early days of the petroleum history it was assumed that most of the gas was produced. It was believed that residual gas saturation only counted for 1-15 per cent of the pore space. Later it was discovered by Geffen *et al.* (1952) that the residual gas saturation can be as high as 15-50 per cent of the pore space. After this the importance of finding residual gas saturation was recognized.

A lot of research has been dedicated to finding factors that will affect the residual gas saturation. It has been discovered that permeability, porosity, initial saturations and rate of displacing fluid affects the amount of trapped gas in the reservoir.

There are several ways of finding S_{gr} in the lab. It is very difficult to preserve the core at its reservoir state, so normal procedure is to restore the core before doing experiments. When this is done either a steady state or unsteady state method can be used to determine S_{gr} in the core.

Trapped gas is still subjected to a lot of research since there are areas that are not completely understood. As oil reservoirs diminishes, it gets more and more important to gain good knowledge about gas reservoirs.

2 Theory

2.1 Definition

When gas is produced either from natural depletion or from injection of water there will be some gas left in the reservoir, which is referred to as trapped gas. When one immiscible fluid is displacing another, it is impossible to reduce the saturation of the displaced fluid to zero. At some stage the displaced fluid ceases to be continuous, and the flow decreases. At this point there will be a fraction of the displaced fluid left in the reservoir which is called residual saturation. Even though the recovery factor is normally much larger in a gas reservoir than in oil reservoirs, there is still some residual gas. In general the maximum residual gas saturation varies between 0.05 and 0.95. (Suzanne *et al.* 2003)

There has been done a lot of research, to figure out why there will always be residual gas saturation. This process is still not fully understood. Many scientists have tried to find a trend between residual gas saturation and other parameters such as porosity, permeability, rock characteristics and initial gas saturation. There is not found any correlation between trapped gas and permeability and only a very general trend between porosity and residual gas saturation. (Legatski *et al.* 1964)

Agarwal *et al.* (1965) found that gas recovery is dependent on 4 factors: production rate, residual gas saturation, aquifer properties and volumetric displacement efficiency of water invading the gas reservoir.

The most important mechanism for trapping gas in pores is the disconnection by choke-off mechanism. This occurs more frequently for higher aspect-ratio porous media. High aspect-ratios are a result of quartz overgrowth in the pores, which decreases pore-throat size more than the pore-body size. If the pores are subjected to consolidation and it proceeds to a point where some throats are filled, the number of connected pores will decrease. This will reduce the paths for gas to escape, and thus the trapping will increase. If the grains are poorly sorted the level of trapped gas will also be high. (Jerauld 1996)

2.1.1 Terminology

The definition of trapped gas can be expressed as the total amount of unrecovered gas in the liquid-displaced volume of the reservoir, see **Fig. 2 - 1.** This means that trapped gas comprise both residual gas and unswept gas in the liquid invaded zone. Residual gas is the gas which does not move even though it is in the liquid-swept region. The unswept gas is the gas placed in disconnected pores, which means that it will never be possible to produce this gas. The amount of trapped gas can be determined by Eq. 2-1 or Eq. 2-2, which is derived from material balance. (Batycky *et al.* 1998)

$$G_t = G_i - G_p - G_c \qquad (2\text{-}1)$$

Where

G_t = amount of trapped gas, in sm^3

G_i = amount of initial gas, in sm^3

G_p = amount of produced gas, in sm^3

G_c = amount of gas in the non invaded zone (the gas in the gas cap), in sm^3

Trapped gas can also be expressed by Eq. (2-2)

$$G_t = G_r + G_u \qquad (2\text{-}2)$$

Where

G_r = amount of residual gas in the invaded zone, in sm^3

G_u = amount of gas that have been bypassed, in sm^3

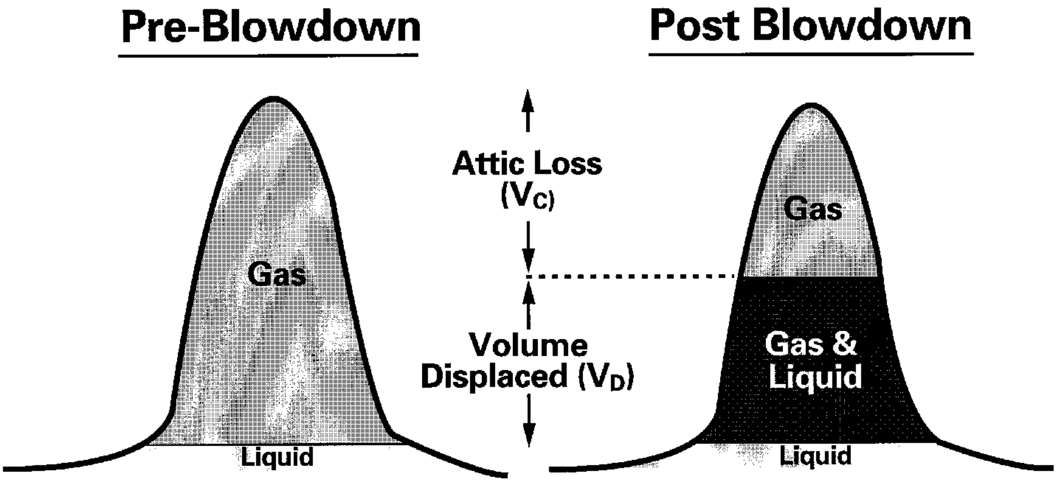


Fig. 2 - 1 - A gas production scenario (Batycky et al. 1998)

2.1.1.1 Recovery factor

To predict how much of IGIP that will be produced, it is standard to calculate recovery factor. This is calculated by dividing the assumed amount of gas produced with IGIP. This will quickly give a good estimate of total gas production and if it economically to proceed. Recovery factor can be calculated by **Eq. (2-3)**.

$$RF = \frac{G_p}{G_i} = \frac{G_i - G_t - G_c}{G_i} \tag{2 -3}$$

2.1.2 Optimum production scenario (SPE 59772)

El-Banbi et al. (2000) studied gas-condensate reservoir and they tried to find which method would give best production. Either gas injection, water injection or natural depletion of the reservoir. The study showed that injection of either gas or water would give a higher production than depletion. Water would be the best alternative since gas would give higher production costs.

2.2 Research on trapped gas through time

The article *"Efficiency of Gas Displacement from Porous Media by Liquid Flooding"* by Geffen et al (1952) was one of the first articles addressing the issue of trapped gas. One aim with this research was to compare the measured residual gas saturation from laboratory and field experiments. It was concluded that residual gas saturation determined in the lab is representable for the actual value of a gas reservoir. Previously it was assumed that the residual gas did not count for more than 1-15 per cent of the pore space. By executing different water flooding experiments on sandstone cores, Geffen *et al.* (1952) discovered that residual gas saturation vary from 15-50 per cent of the pore space. This indicated that a relatively high gas saturation get trapped in the reservoir after water flooding, which led to a wider interest on the subject of trapped gas.

During the 1960's more focus was directed at the issue of trapped gas. Agarwal *et al.* (1965) studied water influx and its influence on gas production. The study also tries to connect the amount of residual gas to reservoir properties. It was concluded that for a reasonably homogeneous reservoir, the gas recovery may be very sensitive to gas production rate. The experiments showed that the higher the rate the less trapped gas. This can be obtained by lowering the abandonment pressure.

Land (1968) derived an equation for calculating trapped gas. By looking at published data, Land (1968) discovered an empirical relation between residual and initial gas saturation. See eq. (). This equation is highly recognized as a good method for calculating the residual gas saturation. Most recent studies find that the results obtained are in good correlation with this formula.

Throughout the 70's, 80's and 90's, the issue of trapped gas was not given much attention. Still there were some scientists that addressed the subject, like Firoozabadi et al. (1987). They tried to find a connection between trapped gas saturation and initial water saturation. They found that as the initial water saturation increases the trapped gas increases.

At the beginning of the 21 Century, more articles on the subject were published. This might be due to discovery of several gas fields and the fact that there is not that much oil left. The objective is to minimize the residual gas saturation, and to find the best methods for doing that. Ding and Kantzas (2004) tried to estimate residual gas saturation by using different imbibition methods, and find which factors may affect it. They found that both initial saturations and rock properties will affect the residual gas saturation.

2.3 Aquifer

Still today there are a lot of uncertainties concerning aquifers. This is because wells are rarely drilled into the aquifer. This means that the knowledge about water influx is gained by studying the reservoir. The water influx will play an important role in the prediction of gas reserves and the amount of trapped gas. If good knowledge is gained about the aquifer, it is more likely to get a good plan of how to develop the field. Many models have been generated for calculating water influx. Allard and Chen (1988) derived an equation for calculating the water influx see **Eq. (2-4 – 2-5)**.

$$W_e = B \Delta p W_{eD} \tag{2 -4}$$

$$B = 1.119 \phi h c r_R^2 \tag{2 -5}$$

Where

W_e = water influx

B = water influx constant

Δp = pressure difference

W_{eD} = dimensionless water influx, only dependent on dimensionless time

φ = porosity

h = aquifer thickness

c = effective aquifer compressibility

r_R = reservoir radius

By using SI units and circular drainage there is no need to include B in Eq. 2-4.

Many gas reservoirs are placed above an aquifer, which provide a pressure support. This will lead to a natural depletion in the reservoir which will produce gas through the production wells. When gas is producing, there will be a pressure drop in the reservoir. This causes the aquifer to expend into the reservoir, and provide a pressure support. The more active the aquifer the less pressure drop. (Olarewaju 1989)

When a fractured gas reservoir is placed above an active aquifer the water coning can result in excessive water production. This can kill wells, which will be very costly. This is one of the reasons it is essential to gain knowledge about the aquifer and its activity level. (Li and Horne 2000)

The aquifer can either be bottom-water drive or edge-water drive, see **Fig. 2-2**. Bottom-water drive aquifer will occur where the reservoir has a dip and a large areal extent underlain by an aquifer. (Olarewaju 1989) Edge-water drive reservoir will occur where the flow vectors in the aquifer is horizontal. (Allard & Chen 1988) Since the amount of trapped gas is dependent on the influx of the aquifer, it is important to define the aquifer for each reservoir.

Agarwal *et al.* (1965) developed a method for determining gas recovery, with the assumptions that the reservoir is homogenous and that the aquifer will be edge-water drive. Later Olarewaju (1989) found a method for predicting reservoir performance, by combining the gas material balance equation and an analytical water influx model which accounts for both edge-water and bottom-water influx.

Li *et al.* (2010) studied the activity level of aquifers. They concluded that it could be classified into three types: active, moderate active and inactive influx. The recovery factor of gas is influenced by the activity level of the aquifer. Li *et al.* (2010) found that an inactive aquifer will give the best gas recovery.

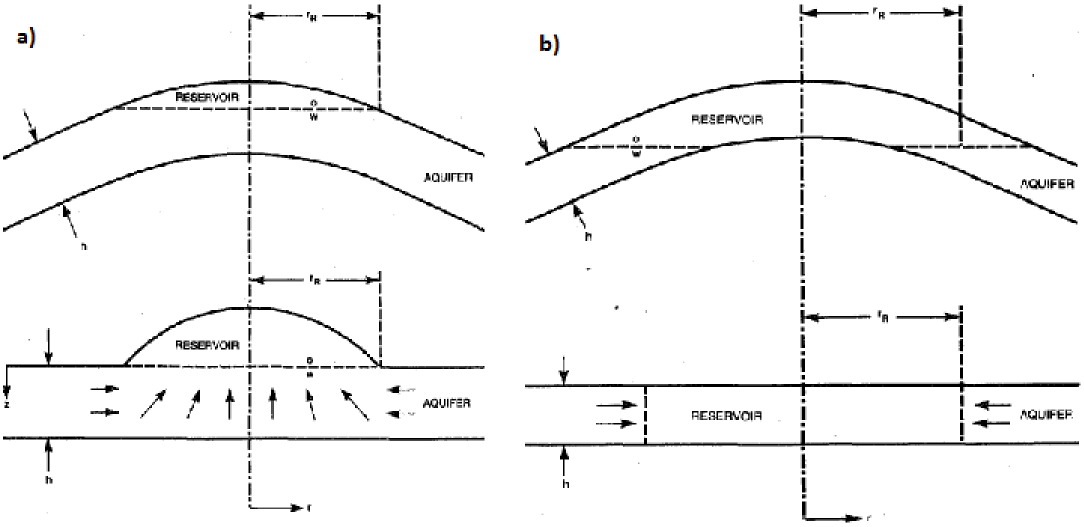


Fig. 2 - 2 - Aquifer, (a) Bottomwater drive reservoir, (b) Edgewater drive reservoir (Allard & Chen 1988)

2.4 Imbibition

The process of wetting phase displacing the non-wetting phase in a pore system is called imbibition. This can happen both spontaneously or forced. In this study the wetting phase is IsoparL and the non-wetting phase is gas. There are different types of imbibition. If the wetting phase is imbibing into a dry sample, the process is called primary imbibition. When the reservoir sample contains initial wetting-phase saturation, the imbibition process is called secondary imbibition. (Li & Horne 2000)

The imbibition process is dependent on two factors; wettability of the rock and capillary forces. If the reservoir strongly wetted by the wetting fluid the dragging effect on the fluids will be strong and the wetting fluid will invade the core faster than if the rock is weakly wetted. The interfacial tension (IFT) need to be large for the capillary forces to be dominant. If capillary forces are dominant the imbibition will be spontaneous, the core will suck the wetting fluid up. If the IFT is weak, viscous forces will be dominating. Viscous forces are the force created by difference in viscosity of the fluids; it is also normally referred to as Darcy force.

Due to the fact that spontaneous imbibition is a capillary dominated process, the imbibition rate and extent are dependent on pore fluids, rock properties and interactions between them. Some of these parameters are permeability, porosity, pore structure, matrix size, fluid viscosities, initial water saturation, wettability, and interfacial tension between the two phases in the system. (Li & Horne 2000)

When a core is subjected to a spontaneous imbibition process, the weight will increase rapidly as capillary forces are sucking the wetting fluid in. When this process ceases to exist, the core will still increase in weight, due to diffusion of gas into the wetting phase. This weight increase will be very slowly, but if it went on for infinity the core might be fully saturated again.

In areas of high drawdown the process of water displacing gas will be forced imbibition, while in areas of low drawdown this process will be spontaneously imbibition. Forced imbibition happens when there are other positive pressure gradients. (Kantzas *et al.* 2000)

Even though most of the research in the petroleum industry focuses on oil, some methods have been developed for characterizing spontaneous water imbibition in gas reservoirs. The most commonly used method is the Handy equation, see Eq. 2-6 (Li & Horne 2000)

$$N_{wt}^2 = A^2 \frac{P_c k_w \varphi S_{wf}}{\mu_w} t \qquad (2\text{ -}6)$$

Where

N_{wt}^2 = volume of water imbibed into the core

A = cross-section area of core

P_c = capillary pressure

k_w = effective permeability of water

φ = porosity

S_{wf} = water saturation behind the water front

μ_w = viscosity of water

t = imbibition time

Spontaneous water imbibition can take place in most reservoirs except those that are not water-wet. It is very important to study the spontaneous imbibition process since it is essential for predicting the production performance. (Li and Horne 2000)

2.4.1 Wettability

In a system where gas is present, gas will always be the non-wetting phase. The degree of wetting can vary with composition of the rock surfaces and the gas and liquid phase. When the wetting phase which is displacing the gas is strongly wetting, the spontaneously imbibition process will control recovery and residual saturations. If the contact angle is large or if another non-displacing fluid is present the liquid phase may not be strongly wetting.

When this is the case, viscous forces play an important role. The most important effect of wetting degree is that the residual gas will be lower when viscous forces are dominant. (Batycky *et al.* 1998)

Kantzas *et al.* (2000) studied how wettability affects the gas recovery when executing spontaneously experiments. If the initial rate of imbibition is high, the wetting-phase will move quickly into the pore space, and it implies strong wetting conditions. Kantzas *et al.* (2000) looked at the relationship between gas recovery and Amott wettability index, and found that gas recovery increases as the Amott WI increases. Hence the gas recovery increases with water-wetting grade. This result is in accordance with studies done for a water-oil system. For an oil-water system a lot more research has been executed, so more data are available. It is found that an intermediate wettability might also give very good oil recovery.

2.4.2 Capillary pressure

Four types of forces are working on the fluids in a pore system: surface, gravitational, viscous and capillary forces. The surface forces are attracting the wetting phase to form a molecular film covering the rock surface, while the capillary forces creates a curved interface between the wetting phase and the gas, see **Fig. 2-3.** If the wetting phase forms a continuously film along the rock surface the capillary pressure can be calculated by using Young-Laplace formula, see Eq. (2-7) (Newsham *et al*. 2004)

$$P_c = \frac{2\sigma\cos\theta}{r} \tag{2 -7}$$

Where

$P_c =$capillary pressure

$\sigma =$surface tension

$\theta =$contact angle

$r =$ pore throat radius

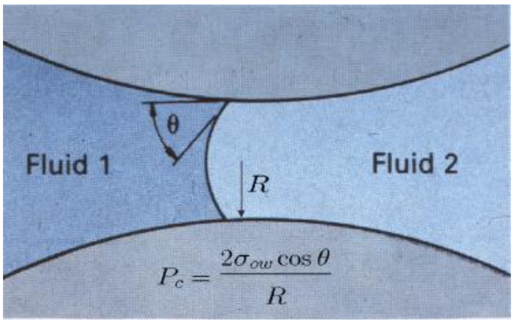


Fig. 2 - 3 - Interface between two fluid in a pore (Tran 2006)

To estimate the trapped gas saturation, a wetting fluid needs to displace the gas. This process is called an imbibition process. In order for the wetting fluid to displace the gas in a pore, it need to first pass through a pore throat. For this to happen, the pressure in the wetting phase needs to exceed the pressure in the non-wetting fluid by the threshold capillary pressure. This capillary pressure can be calculated by Eq. (2-7). (Newsham *et al.* 2004) During a spontaneous imbibition process, the wetting phase gets sucked into the core by capillary forces.

2.4.2.1 Estimating capillary pressure curves

By using a porous plate, it is possible to create a capillary pressure curve. A core with different porethroath sizes is installed inside a coreholder, with a water-wet semi permeable disk placed at the production end. The water-wet permeable disk will only allow water through. First the non-wetting phase, in this case gas is injected into the core at a low P_c, see **Fig. 2-4.** Each tube represents one porethroat size which have different threshold pressure for the entry of the non-wetting phase. The biggest porethroats has the lowest threshold capillary pressure (see. Eq. 2-7) and will be filled first. S_w can be calculated by measuring the water produced.

As capillary pressure increases, smaller and smaller porethroats can be filled with the non-wetting phase, and S_w will decrease. When the core is saturated with connate wetting phase, capillary pressure curve can be made based on these measurements, see **Fig. 2-5.** These data will end up as the primary drainage curve in Fig. 2-5.

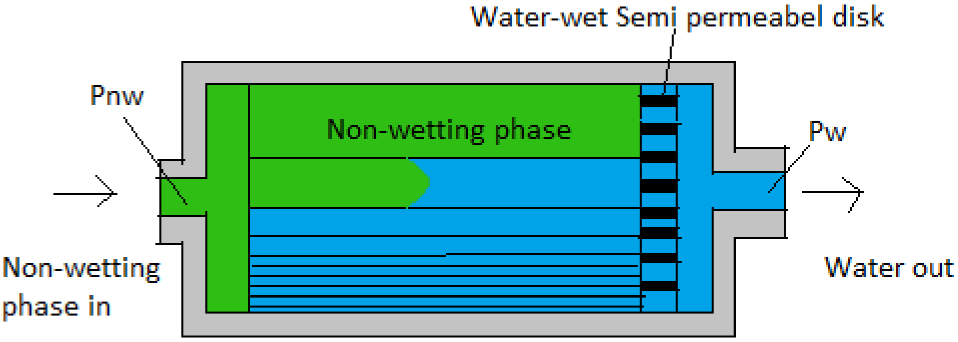


Fig. 2 - 4 - Capillary tubing

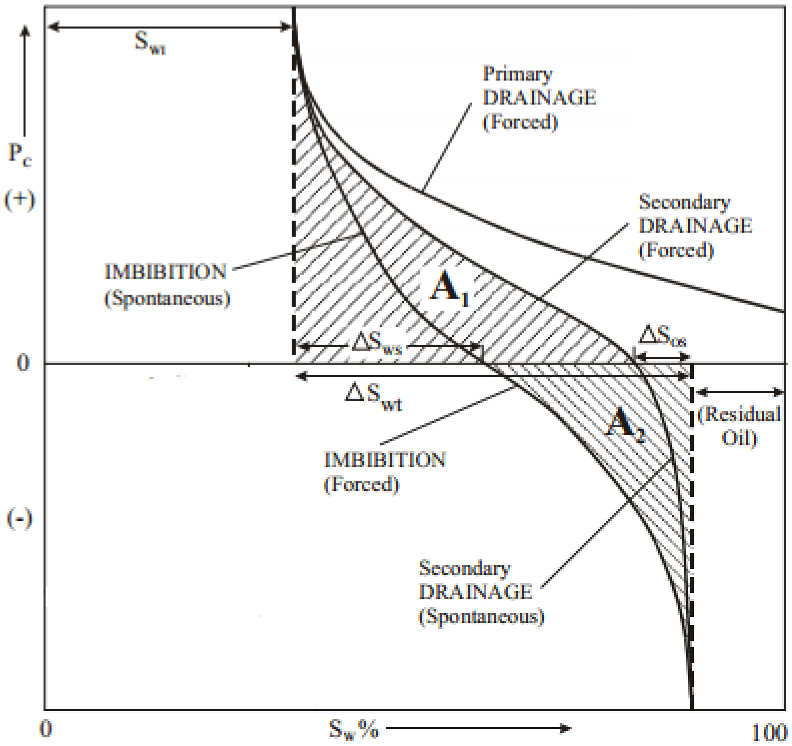


Fig. 2 - 5 - Capillary pressure curves, for imbibition and drainage process (Torsæter and Abtahi 2003 with adjustments)

When a core with S_{wi} saturation comes in contact with the wetting fluid, there will be a spontaneous imbibition process, which will suck the wetting phase into the core, while P_c decreases. This process is represented by the imbibition line in Fig. 2-5. When P_c becomes zero, the imbibition process will not happen spontaneous anymore.

By using Eq. (2-8) it is possible to calculate how far into the core the wetting phase will imbibe spontaneously.

$$h = \frac{P_c}{\Delta\rho g} \tag{2 -8}$$

Where

h = length of infiltration into the core

P_c = capillary pressure

Δρ = density difference

g = gravitational constant

When spontaneous imbibition flow ceases to exist there is still a lot hydrocarbons left in the core. By forcing a wetting fluid into the core, more hydrocarbons can be produced. For this process capillary pressure will be negative, see Fig. 2-5.

For deciding the saturation distribution it is important to get a good understanding of the capillary pressure in the reservoir.

2.4.3 Viscous forces

If the core is flooded with a set rate that is higher than the spontaneous imbibition rate, the core will be exposed to forced imbibition. When that is the case viscous forces are dominating.

Darcy's law is a viscous flow law, see Eq. 2-9.

$$F_v = \Delta P A = \frac{Q \mu_{IsoparL} L}{k_{IsoparL}} \tag{2 -9}$$

Where

F_v = viscous force

ΔP = differential pressure

A = cross sectional area

Q = rate

μ = viscosity

L = length of the core

k = permeability

By looking at Darcy's law it is clear that the viscous force is dependent on rate, viscosity and permeability. When injected rate exceeds the spontaneous imbibition rate the process will be a viscous dominated process.

2.4.4 Imbibition front

In a reservoir there will be a lot of different pore sizes. The wetting phase will infiltrate bigger pores easier than smaller pores. The pore system in **Fig. 2-6a-2-6c** will be used to illustrate how a wetting phase might infiltrate the core to recover hydrocarbons and how gas gets trapped.

When the front is controlled by capillary forces it goes easily through the larger pores, but not as easy through smaller pores. As seen in Fig.2- 6a wetting fluid will flow through larger pores and remove gas. By looking at Fig. 2-6b it is clear that fewer paths are made through smaller pores. In Fig. 2-6c the forced front from the pump reaches the capillary front. The forced front will have a higher rate, and will therefore only follow the fluid path in the smaller pores that has been created by the capillary front. This result in the gas getting trapped in the smaller pores.

If rate is increased, the forced front will reach the spontaneous front earlier, and even fewer paths have been made through small pores. This will result in more gas getting trapped.

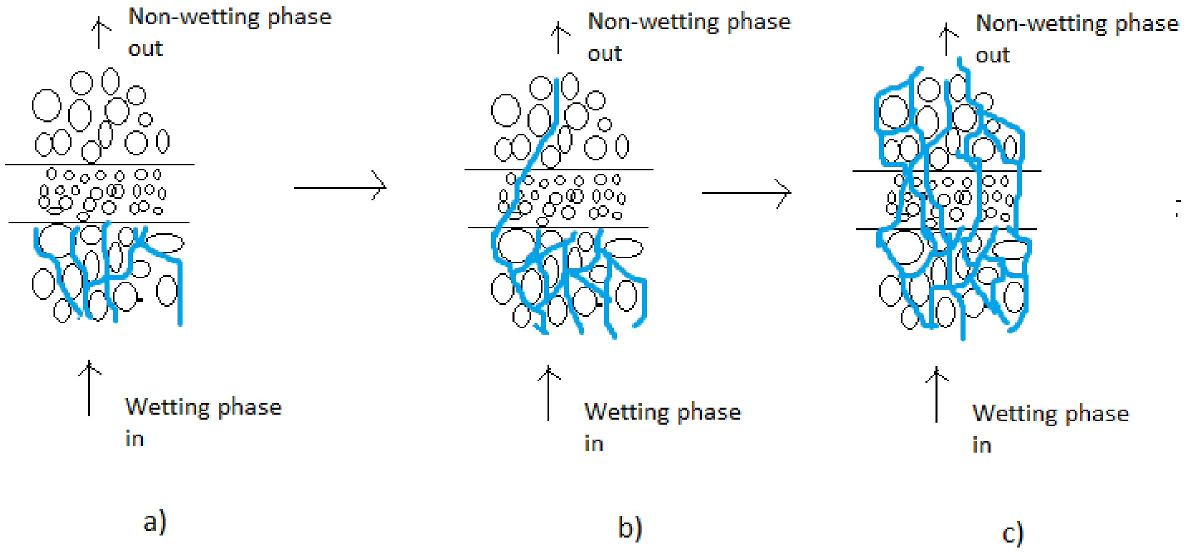


Fig. 2 - 6 - A pore system with different pore sizes

2.5 Calculating trapped gas

Land (1968) developed a formula for calculating residual gas. By studying data from released papers, he developed an equation. This formula is based on the fact that trapped gas saturation is dependent on initial gas saturation. It was discovered that the difference in value of initial and residual gas saturation are approximately constant for a given sand. Based on the assumption that when the initial gas saturation is unity the residual gas saturation is the maximum residual gas saturation, Land developed an equation that estimates residual gas saturation, see Eq. (2-10) and Eq. (2-11).

$$C = \frac{1}{S_{gr}^*} - \frac{1}{S_{gi}^*} \qquad \text{(2 -10)}$$

$$S_{gr}^* = \frac{S_{gi}^*}{1 + C S_{gi}^*} \qquad \text{(2 -11)}$$

Where

$C = \frac{1}{(S_{gr}^*)_{\max}} - 1$ = Land coefficient

S_{gr}^* = effective residual gas saturation, expressed as fraction of the pore volume excluding the pore volume occupied by irreducible water

S_{gi}^* = effective initial gas saturation

Land's equation is still being used today, and it is recognized as a good estimation of residual gas saturation.

Jerauld (1996) suggested that almost no gas is trapped in microporosity. Due to this assumption it was proposed that a zero-slope generalization of the Land curve can better represent trapped-gas data. Jeraulds equation is shown in Eq. 2-12

$$S_{gr} = \frac{S_{gi}}{1 + \left(\frac{1}{S_{grm}} - 1 \right) \cdot S_{gi}^{\left(\frac{1}{1 - S_{grm}} \right)}} \qquad \text{(2 -12)}$$

2.6 Trends, what affect trapped gas?

To be able to give a good estimation of how much trapped gas there will be in a reservoir, it is important to look at factors that will affect this saturation. A lot of research has been carried out to find a connection between trapped gas and reservoir and liquid properties, like porosity, permeability, initial saturations, grain density, formation factor and wettability. Reservoir and liquid properties are basic parameters that will be measured for every reservoir, so if a trend can be found with trapped gas and these basic parameters, it would be easier to predict trapped gas saturation for each reservoir.

2.6.1 Porosity and permeability

Legatski *et al.* (1964) discovered that there was a weak trend between trapped gas and porosity, and no trend between trapped gas and permeability. The measurements showed that as porosity decreases the residual gas decreases.

Jerauld (1996) did experiments on samples from the Prudhoe Bay reservoir. The results from the trapped gas experiments showed that maximum trapped-gas decreases as porosity increases. This might be because low-porosity samples are poorly-sorted. He also suggested that microporosity plays an important role for the amount of trapped gas in the reservoir. Since the microporosity does not trap gas, the more microporosity, the less trapped gas. An explanation for the lack of trapping in microporosity is that chert, which is a major source of microporosity, is very porous with a porosity of around 40%. When studying the pores in a microscope, Jerauld (1996) discovered that the body-to-throat aspect ratio of chert is small, which indicates that it should be little trapping of gas. Another likely mechanism for gas not to be trapped in microporosity is diffusion from micropores to macropores driven by capillary pressure.

Hamon et al. (2001) did experiments to find the maximum residual gas saturation (S_{grM}). They found that there is a trend between S_{grM} and porosity, but they concluded that it is not possible to predict S_{grM} by only using porosity. In addition other inputs, like microporosity are needed. They also discovered a trend between S_{grM} and clay content. S_{grM} will decrease as the clay content increases. They also discovered that microporosity affects the trapped gas. S_{grM} decreases as microporosity increases. Hamon et al. (2001) proposed that microporosity does not trap gas.

Ding and Kantzas (2004) did experiments on a total of 47 core plugs. When looking at the resulting residual gas saturation for these plugs they did not find a clear trend to either porosity or permeability. Instead they discovered a weak trend between the combinations of properties: $\ln\left(\frac{k}{\varphi}\right)$. The residual gas saturation decreases with increase of $\ln\left(\frac{k}{\varphi}\right)$. Even though not clear some trend between porosity and residual gas saturation were discovered. If the samples were divided into different groups it was seen that residual gas saturation decreases with porosity increase for sandstone and increase with porosity for carbonate.

Suzanne *et al.* (2003) discovered a weak trend between porosity and residual gas saturation. As porosity increases, residual gas saturation increases.

2.6.2 Initial gas saturation

A parameter that has been recognized as an important factor in determining residual gas is initial gas saturation. Many scientists have tried to find a relationship between the initial and residual gas saturation.

Firoozababadi *et al.* (1987) studied 8 cores both consolidated and unconsolidated, where the aim was to find residual gas saturation. Water was injected into the cores at a constant rate in vertical direction. It was found a trend that implies that trapped gas increase as the initial water saturation decreases.

Suzanne *et al.* (2003) presented trapped gas experiments on a large set of sandstone samples from two different reservoirs. Sixty experimental relationships between residual and initial gas saturation (S_{gr} and S_{gi}) were executed. It was found that S_{gr} is dependent on S_{gi}, and that this relationship will have a linear form. As initial gas saturation increases the residual gas saturation will increase. It was also concluded that residual gas saturation is dependent on microporosity.

Li and Firoozabadi (2000) did experiments on gas recovery, where both water and oil were used as the wetting phase. They found that when initial wetting phase increases, the gas recovery by imbibition decreases. It was also discovered that imbibition rate increases when the initial wetting phase increases.

2.6.3 Spontaneous imbibition rate

Ding and Kantzas (2004) found a relationship between imbibition rate and residual gas saturation. They discovered that an increase in initial imbibition rate will give smaller residual gas saturation.

The initial imbibition rate is calculated from the water imbibition vs imbibition time plot. It is calculated from the slope at the first several minutes until it reaches the production plateau. (Ding *et al.* 2003)

2.6.4 Reservoir pressure

The amount of trapped gas is dependent on the reservoir pressure. As the pressure in the invaded zone changes with time, the amount of trapped gas changes. The pressure in the invaded zone is affected by the withdrawal history and the response of the underlying aquifer. If the reservoir pressure in the invaded zone increases with time, G_t will remain the same. A decrease in pressure will lead to a reduction in the volume $G_{t.}$. (Batycky *et al.* 1998)

3 Methods for finding trapped gas in the lab

The amount of trapped gas in a reservoir can be measured in the lab by using the principle of spontaneous imbibition, and forced imbibition. There is no method that is accepted as an ultimate method. That is why different methods are recognized as good methods for determining residual gas saturation. Before any of these tests can be executed the core samples need to be cleaned, dried, saturated with wetting phase and finally driven to initial saturations of gas and wetting phase.

3.1 Steady-state displacement

Steady-state method is necessary for obtaining complete relative permeability curves. In this method the wetting phase and the gas are injected simultaneously into the core sample. The rate-gas ratio is incrementally increasing as injection proceeds. Steady-state flow is obtained when the system reaches pressure equilibrium. For each incremental ratio the relative permeability's for both the wetting phase and the gas phase are measured at equilibrium. The increase in wetting phase is also determined. When the test is done and many measurements have been obtained, a graph of relative permeability versus wetting saturation is generated. This method is thorough, but it is costly and time consuming. (Mulyadi *et al.* 2001)

The first step in this procedure is to place the core with initial saturations in a cell, which has a vertical orientation. Flowing fluids are injected from the bottom of the sample. Gas (at higher flow-rate) and wetting phase (at lower flow-rate) are injected simultaneously into the core sample until the pressure drop across the core is stable. This will indicate that the flowing fluids are in equilibrium (steady state) with the pore fluids. When steady-state is reached relative permeabilities and wetting saturation is measured. The process of injecting gas and wetting phase is repeated several times, incrementally increasing the flow rate of the wetting phase with respect to gas. This will lead to an increase in wetting phase relative permeability, a decrease in gas relative permeability and an increase in wetting phase saturation. At the end only wetting phase is injected into the core sample until residual gas saturation is obtained. (Mulyadi *et al.* 2000)

3.2 Unsteady-state displacement

When using unsteady-state technique, the only fluid injected into the core sample is the displacing fluid (wetting phase). For this method, only data from the end points can be measured. This mean that at the beginning of the test relative permeability to gas at immobile wetting phase saturation ($K_{rg} @ S_{wi}$) can be measured, while at the end of the test relative permeability to wetting phase at residual gas saturation ($K_{rw} @ S_{gr}$) can be measured. (Mulyadi *et al.* 2001)

3.2.1 Counter-current imbibition

When the wetting phase invades the core from all sides and the gas is being produced from several directions the process is called counter-current imbibition. For this to happen, the core sample needs to be completely immerged in the wetting phase. (Ding & Kantzas 2004) By measuring the weight of the core as it increases when the wetting phase infiltrates the pores the residual gas can be calculated. This is done by using a weight that is connected to a computer. The computer program will give an imbibition curve for weight vs time.

This method will place the residual gas in the middle of the core, and the hight of the core will not affect the residual gas saturation.

This method is the standard method for an oil-water system, but for a gas-wettingfluid system it can be difficult to implement due to some limitations. In a gas-liquid system the rock is normally strongly liquid-wet and the early spontaneously imbibition may happen too quick for the data to be recorded accurately. This is why co-current method is the best method for a gas-liquid system. (Li and Firoozabadi 2000)

3.2.2 Co-current imbibition

Co-current imbibition is a process where the wetting phase invades the core sample from one end and the gas is produced from the opposite end. (Ding & Kantzas 2004) Thus, only one side of the core is in contact with the wetting fluid. The plug is vertically orientated and wetting fluid starts infiltrating at the bottom side of the plug.

By using this method it is easier to imagine how the wetting fluid will flow in the pores. There will be a piston like displacement, one that will push most of the gas out and leave some behind as residual gas.

Residual gas will be found throughout the core where the wetting phase has flooded. The infiltration length is dependent on the capillary pressure; see Eq. (2-8). If the capillary pressure is small the wetting fluid might not be able to push through the whole core, and this might affect the residual gas saturation. So in some cases it might be wise to do some calculations to see if the whole core has been flooded.

3.2.2.1 Spontaneous imbibition

When it is desirable to measure trapped gas by co-current spontaneously imbibition the apparatus in **Fig. 3-1** can be used. Here the core sample is placed in a bucket with holes at the bottom, for the fluid to infiltrate the core. The bucket is hanging from a scale which is connected to a computer. The computer will produce a graph of weight versus time. Imbibition rate can be found from this graph by calculating the slope. Immediately when the core touches the wetting fluid, it will start infiltrating the core. In the beginning it will happen quite rapidly, so it is important to be accurate with the measurements.

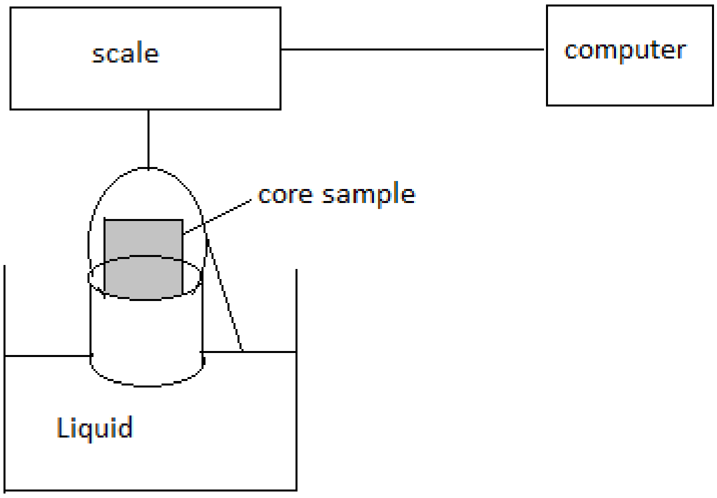


Fig. 3 - 1 - Apparatus for measuring spontaneously co-current imbibition

3.2.3 Centrifuge

In this method the core samples will be exposed to a centrifugal force, while injecting the wetting phase. This will force the mobile gas out. The centrifugal force is created by spinning the samples at increasingly higher speed. This process is an imbibition process. Some advantages with this method are the ability to get capillary data quickly and the possibility to do the experiment at reservoir condition. Many high-speed centrifuges can be operated at reservoir pressure and temperature. (Newsham *et al.* 2004)

3.2.4 Unsteady-state water flood (USS)

In this method wetting phase is injected into the core with constant line pressure, temperature and rate. Sensors for measuring pressure difference between inlet and outlet flow, temperature and liquid type is connected to a computer. The data will be plotted on a graph against time. These measurements will be very accurate. The liquid sensor is placed at the producing end of the core, and will react when it is breakthrough. Then there will be a shift on the graph.

The core is vertically orientated and the wetting fluid will be injected at the bottom end of the core and produced at the top. The wetting fluid will be transported from a burette, through some teflon lines and a pump and into the core. It will push some of the gas out. When it is breakthrough, no more gas will be produced.

This method is ideal for controlling the injection rate. A pump is creating a stable rate throughout the experiment and makes it possible to compare residual gas at different rates.

By observing injected wetting fluid from a burette or by using the weight difference before and after the experiment, residual gas saturation can be calculated.

The execution of this method will be explained in greater detail in chapter 5.

3.2.4.1 Obtaining different pressure differences

When wetting fluid is injected into the core, ΔP will be measured throughout the experiment, see **Fig. 3-2**. What fluid is in the pressure line?

If spontaneous imbibition rate is faster than the rate set by the pump, capillary forces will dominate and ΔP will be negative in the beginning. Commonly if water is the wetting phase and the rate set by the pump is low (4 ml/h), the capillary forces will be stronger than the viscous forces and drag the water faster in than the pump manage to pump it in. This leads to a decrease in ΔP.

After a while the capillary forces will weaken and the spontaneous imbibition rate will decrease. The flow front from the pump will catch up with the rate controlled by capillary forces. This will result in an increase in ΔP and ΔP will be zero when they are exactly the same rate.

Differential pressure will keep increasing and it will be positive throughout the rest of the experiment. The front of the flow through the core will be run by the pump, and viscous forces will be dominating.

It is also possible to start the experiment with a rate that will give ΔP = 0 and ΔP > 0, and see how this will affect the residual gas saturation.

If all of the experiment is executed at the condition where ΔP > 0, the front would be controlled by viscous forces and Darcy's law can be applied. This is because Darcy's law is a viscous law. (see Eq. 2-9)

When the resulting pressures are very small (kPa scale), capillary pressure plays a huge role. If the resulting differential pressures are on a bigger scale like MPa and GPa, capillary pressure will not be of great significance. The process can be studied by only looking at viscous forces, and it would be easier to explain what is happening.

It is still not fully understood how it is possible for ΔP < 0. When pressure difference is negative it implies that the outlet pressure is larger than the inlet pressure. The key to understand this is to get an idea of what is happening at the outlet.

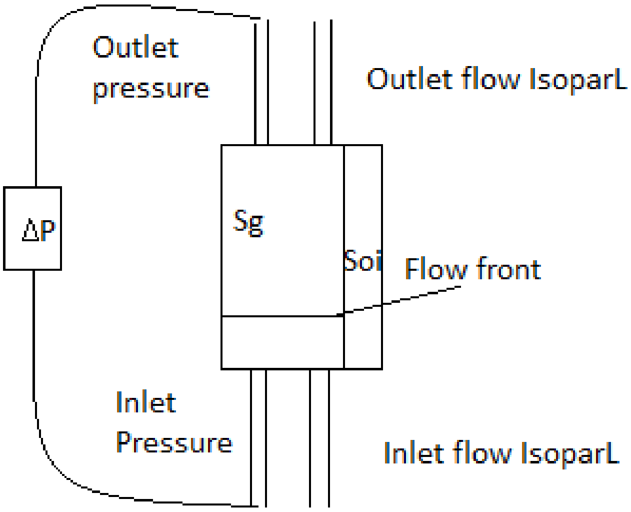


Fig. 3 - 2 - Core in coreholder in USS rig

3.2.5 Porous plate

This method can both be used for drainage and spontaneous and forced imbibition. When the aim is to find trapped gas saturation, an imbibition test will be executed.

A core sample with established initial saturations is placed in a cell filled with wetting fluid and a gas-wet semi-permeable disk. Only gas will be able to flow through this semi-permeable disk. Outlet and pore pressure are established. Initially the pore pressure exceeds the outlet pressure, but to get spontaneously imbibition the capillary pressure is lowered to zero. So the pore pressure is reduced to match the outlet pressure, see **Fig. 3-3**.

The trapped gas can be calculated by reading wetting fluid level in a glass burette. (Bull *et al.* 2011)

During measurement, the pressure is increased in steps and final equilibrium produced volumes of the wetting phase are recorded for each step.

The porous plate method is slow and one full curve may take up to 40 days or more to obtain. However, equipment needed for this method is simple and inexpensive and the work needed is limited to some volume reading during the process. Several samples may be run in one chamber. Then the samples have to be removed in order to weigh them separately between each pressure increase. Preferably, one and one sample should be run in an assembly of one-sample cells. Then it is not necessary to decrease pressure between each reading. (Torsæter and Abtahi 2003)

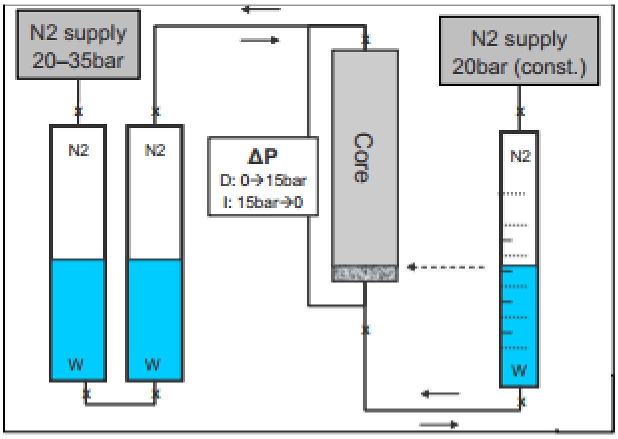


Fig. 3 - 3 - Porous plate experimental set-up (Bull *et al.* 2011)

Since this experiment is very time consuming, it was decided to not use this method in this study.

4 State of the core

4.1 Problems with the condition of the core

The premier goal when handling a core is to obtain the reservoir conditions. Ideally the core should be preserved at reservoir conditions before using the cores for analysis. This is not easy due to a lot of alterations on the core. A lot of factors when handling the core materials can affect the initial conditions before testing and during testing. Important factors altering before testing can be drilling fluid used in drilling operations, packaging and cleaning. During testing, test fluids, temperature and pressure will alter the state of the core. (Anderson 1986a) The core will be exposed for a temperature and pressure drop while it is being brought to the surface. This can lead to a deposition of asphaltenes which can alter the original wettability. (Cuiec 1977)

There are two ways of testing the core at natural state, either preserve or restore the core. As described it is very difficult to preserve the core, so the most common method used in laboratories is to restore the core. Before restoring the core, it needs to be cleaned. This is done to remove all of the materials that have been adsorbed onto the matrix surface. The particles can come from mud, oxidation during handling or from deposits during sampling. When the core is clean, it needs to age under reservoir condition and with reservoir fluids. This way, it will reach a state close to the originally reservoir state. (Cuiec 1977)

When the core is clean, the aim is to re-establish the reservoir original state. That means re-establishing the wettability; by establish S_{wi} and adsorption equilibrium. (Morrow 1990)

4.2 Initial saturation

In this study the only varying factor should be injection rate of IsoparL, so it is very important to keep every other variable constant. That implies that initial saturations need to be the same before every experiment. An important factor for making this possible is to use the same centrifuge with the same rate and for the same amount of time. It is still necessary to weight the cores after centrifuge to make sure that they are about same weight at least within a reasonable % error.

If the initial saturations are kept constant it is more likely the trapped gas resulting from using different injection rates are comparable.

4.3 Choosing the wetting fluid

In a gas reservoir the wetting fluid will be water. So to simulate the reservoir conditions in a most correct way, the wetting fluid in the cores should be water. Previous studies executed by Weatherford laboratories have shown that using water as the wetting fluid will give results with high uncertainties. This is due to the fact that water evaporates quite easy, and will alter the results, when weighing the cores. A good substitute for water has proven to be the light oil IsoparL . It will behave in a similar way as water, but it will not evaporate as fast.

Another reason for using IsoparL instead of water was that it would be easier to establish initial saturations before every experiment. This is because the rock is strongly water wet and would suck much more water than IsoparL, and it would be more difficult to get the same initial saturation every time.

Weatherford laboratories have used IsoparL in previous studies with good results. Based on these facts, it was decided to use IsoparL as the wetting fluid.

5 Experiments

The aim of this research is to find the amount of trapped gas in different core samples, where the ultimate objective is to see how injection rate of the wetting fluid affects trapped gas. The experiments will also give answers to how permeability, porosity and initial saturation affect trapped gas.

Three core samples from both Berea outcrop and a reservoir in the northern sea were prudently selected for this study. The samples were cleaned and dried before executing dry measurements. Both porosity and permeability were measured for dried cores. After establishing the rock properties of all six cores, they were saturated under vacuum with a wetting fluid, which in this experiment was chosen to be IsoparL. Before imbibition tests could be executed the core samples needed to reach a state of initial saturations. This was done in a centrifuge.

Residual gas saturation was established in four different methods: spontaneously imbibition, low rate injection (negative DP), medium rate injection (neutral DP) and high rate injection (positive DP). Between every experiment, initial saturations needed to be established. The only parameter that changes for each experiment is the injection rate.

5.1 Rock properties

In this study three Berea sandstones core samples and three samples from a field in the northern sea have been used.

5.1.1 Berea

The three Berea samples were all cut from the same block. This way the rock properties will be similar for all the three samples, which are desirable since they will be compared based on the same experiment. They had a length and diameter in the range of 4.69-4.74 cm and 3.79-3.81 cm, respectively. Porosity was measured by using helium porosimeter, which gave a result in the range of 16.4-18.3 %. Permeabilities were in the range of 44-55 mD. This was obtained by using the Hassler cell. Dry weight was measured for later reference. The three cores had a dry weight in the range of 116-118 g, see **Table 6-1** in result.

5.1.2 Northern sea core samples

Statoil were able to provide 7 cores from a field in the North-Sea for this master thesis. The samples came from a depth of 3237-3300 m, i.e an interval of 60 m were studied. Due to time limitation three cores were chosen for further studies. The three cores were chosen on the basis of porosity and permeability measurements. A porosity versus permeability plot was made where each point represent a core, see **Fig. 6-1**.

The 7 cores had a wide range of permeabilities, for some as low as 1,6 mD and for some as high as 6370 mD. It was desirable to choose three cores which had similar porosity and permeability properties, and which could be placed on a straight line. From Fig. 7 it can be seen that core N-102, N-105 and N-108 falls on the same straight line. Due to this observation the cores N-102, N-105 and N-108 will be studied further.

These cores had a length and diameter in the range of 4.80-4.85 cm and 3.76-3.80 cm, respectively. The porosity was measured to be in the range of 21-30 %. By using the Hassler cell the permeabilities were measured to be in the range of 24-600 mD. Dry weight was measured for later reference. The three cores had a dry weight in the range of 99-112 g, see table 1 in result.

5.2 Fluid properties

In this study IsoparL was used as the wetting fluid, while dry air was used as the gas phase.

5.2.1 IsoparL

Even though the wetting fluid will normally be water in a gas reservoir, IsoparL was chosen to be the wetting phase in this study. The reason for this is that water evaporates very easily. This might cause alterations in the experiments and eventually lead to unrealistic results. IsoparL has shown to act in a similar way as water, both in interactions with the matrix and the gas, and is therefore considered to be a good substitute for water as the wetting phase. IsoparL will not evaporate as easily as water and is therefore a better alternative for the wetting fluid than water. Based on these facts IsoparL was chosen to be the wetting phase in this experiment.

IsoparL is light oil, which is odorless and colorless. It is a product of petroleumbased raw material, which is treated with hydrogen in the presence of a catalyst. (Exxon Mobile 2011) This results in a product that contains very low levels of aromatic hydrocarbons. Isopar L is widely used in the industry. It is low in toxicity and therefore safe to work with.

The density and viscosity of IsoparL are dependent on the temperature surrounding it; see **Table 6-2** and **Fig. 6-2**. Viscosity and density can be measured by using a viscometer. By measuring viscosity and density at different temperatures for IsoparL it is possible to get a reference frame, see Table 2. In this study the most common temperature has been 25 °C. By using Eq. (5-1) to interpolate, it is possible to find the density and viscosity of IsoporL at this temperature.

Interpolation formula:

$$y = y_a + (y_b - y_a)\frac{(x - x_a)}{(x_b - x_a)} \qquad \text{(B -1)}$$

Finding density and viscosity of IsoparL at 25 °C:

$$\rho_{@25^\circ C} = 0.7598 + (0.7528 - 0.7598)\frac{(25-20)}{(30-20)} = 0.7563 g/ml \qquad \text{(B -2)}$$

$$\mu_{@25^\circ C} = 1.326 + (1.119 - 1.326)\frac{(25-20)}{(30-20)} = 1.223 cp \qquad \text{(B -3)}$$

5.2.2 Dry gas

Dry air was used as the gas face in this study. The density and viscosity of dry air is also dependent on temperature. The density can be calculated by using the ideal gas law, see Eq. 5-4.

$$\rho_{dryair} = \frac{p}{R_{specific}T} \qquad \text{(B -4)}$$

Where

P = absolute pressure at ambient conditions = 1 atm

$R_{specific}$ = specific gas constant =287.058 J/kgK

T= absolute temperature

From Eq. (5-4) it is calculated that at 25 °C the density of dry air is 0.00118g/ml

A formula has been derived for calculating gas viscosity, see Eq. 5-5.

$$\mu_{dryair} = 4.69\cdot 10^{-11}T^3 - 4.25\cdot 10^{-8}T^2 + 5.12\cdot 10^{-5}T + 1.74\cdot 10^{-2} \qquad \text{(B -5)}$$

By implementing different temperatures in Eq. 5-5, the result will be a graph as seen in **Fig. 6-3**. The viscosity for dry air at 25 °C is 0.0186 cp. This can be obtained either by reading from the graph or using Eq. 5-5.

5.3 Preparations and basic measurements

5.3.1 Cleaning

All the cores needed to be cleaned. This to remove all unwanted particles, like mud from the reservoir and dust that might have altered the cores.

The samples were placed in a sleeve in core holders surrounded by light viscous oil. The sleeve pressure was pumped up to 30 bar, to prevent the sleeve oil to come in contact with the core. The purpose of using a core holder while executing different experiments is to be able to have the cores in reservoir conditions.

The samples were cleaned with toluene for one day and with methanol for 2 days, with a rate of 4 ml/h, a pressure of 30 bar and a temperature of 70°C. It was observed that liquid going through the cores after three days were colorless, hence the cores were properly cleaned.

After removing the cores from core-holders, they needed to dry in an incubator for a couple of days. This was done to prepare the cores for dry measurements.

5.3.2 Porosity

Porosity is a key parameter in determining the amount of gas in the reservoir, and when finding the residual gas saturation. It describes how large part of a rock that can contain fluid. In this experiment effective porosity is measured, which is the ratio of the interconnected pores and the bulk volume.

For measuring the porosity, a helium porosimeter was used. Helium is injected into an empty cell and volume of helium is measured (V_2). Then a core is placed in the cell, and the volume of helium is measured (V_1). V_1 will be smaller than V_2. By using Eq. 5-6 – 5-8 effective porosity is calculated.

$$V_k = V_2 - V_1 \qquad \text{(B -6)}$$

Where

V_k = volume of matrix

V_2 = volume of helium in an empty cell

V_1 = volume of helium in a cell with a core

$$V_b = \pi \cdot r^2 \cdot L \tag{B -7}$$

Where

V_b = bulk volume

r = radius of core

L = length of core

$$V_p = V_b - V_k \tag{B -8}$$

Where

V_p = pore volume

$$\varphi_{eff} = \frac{V_p}{V_b} \tag{B -9}$$

The resulting effective porosities are shown in table 1 in results.

5.3.3 Permeability

Permeability is the capacity of the rock to transmit fluids through the pores. It is dependent on effective porosity and pressure.

Permeability was measured by using a Hassler cell, see **Figs. 5-1 and 5-2**. Air was used as the flowing fluid. Since dry air will not alter the core minerals and it will achieve 100 % saturation fast, this is a good fluid to use. By varying inlet pressure, $P_{1,}$ and outlet pressure, P_2, while keeping the pressure different constant, fluid flow was measured. Four measurements were executed for each core and plotted on a graph, see Appendix A. The absolute air permeability was found by plotting the air permeability's in a graph and read the value were a straight line through the points will cross the y-axes. The permeabilities read from graph are presented in table 1 in results.

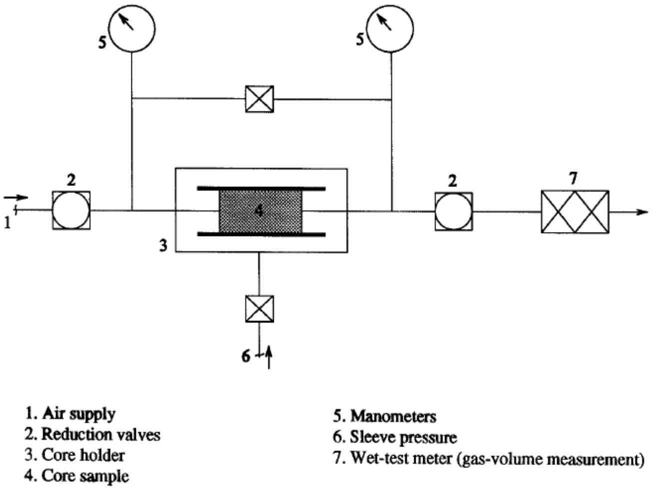


Fig. 5 - 1 - Apparatus for measuring air permeability

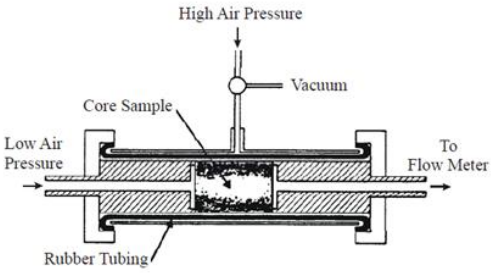


Fig. 5 - 2 - Hassler type core holder

5.4 Establishing initial saturation

Initial saturation need to be established before every experiment. It was very important that this was executed the same way every time, to make sure that the cores had the same initial saturation before every experiment. That implements using the same centrifuge with the same rate for the same amount of time

5.4.1 Saturation

When dry measurements have been executed, the cores can be saturated with IsoparL. This was done under vacuum, which were created by a vacuum pump. When a good vacuum were reached, IsoparL were poured into the container containing the cores. Due to the vacuum the IsoparL will be sucked into the cores and saturate them.

There might still be some gas left in the pores. To make sure that all gas was removed from the pores, the cores were flooded with IsoparL with a back pressure of 10 bar. The cores were flooded with a rate of 2 ml/h.

While flooding the core, liquid permeability can be measured. This is done by varying the rate and reading the change in pressure difference. By using Darcy's law, see Eq. (5-10) it is possible to calculate the liquid permeability.

$$k_{IsoparL} = \frac{Q\mu_{IsoparL}L}{\Delta PA} \tag{B -10}$$

After the cores have been totally saturated with IsoparL, initial saturations need to be established. This is done in a centrifuge.

5.4.2 Centrifuge

To obtain initial saturations in the core, a drainage process need to be executed. A centrifuge was used for the process of removing and replacing the wetting phase (IsoparL) with the non wetting phase (dry air). The centrifuge had a speed of 5000 RPM. This speed was used to obtain a Bond number of $5.9 \cdot 10^{-7}$. It is very important that this will be executed the same way every time. That implements using the same centrifuge with the same rate for the same amount of time. This is to make sure that the initial saturations will be the same every time.

The cores need to obtain initial saturation before executing the different experiments, to re-establish the reservoir original state.

The cores were weighed before and after the centrifuge, and the volume of IsoparL could be calculated based on the weight difference. Produced IsoparL was also read from a burette to compare with the calculated result. By using Eq. 5-11 – 5-13 initial saturations can be calculated. The results can be found in **Table 6-3** in results.

$$PV = V_b - V_m \tag{B -11}$$

$$S_{oi} = \frac{V_{IsoparL,after,centrifuge}}{PV} \tag{B -12}$$

$$S_{gi} = 1 - S_{oi} \tag{B -13}$$

Even though the same centrifuge was used with the same speed and time, the initial saturations varied a bit. If the IsoparL saturation was higher than previous results, it was possible to place the core in an incubator and let some of the IsoparL evaporate. If it was lower, there was not much to do. In most cases the initial saturation matched fairly well, see table 3.

From table 3 it is clear that the plug Berea 3 has the most consistent initial saturations. So when the data is analyzed, this core will be given extra focus.

5.5 Spontaneous imbibition

It was decided to use the method of co-current imbibition to execute the spontaneous imbibition experiment. This method was chosen due to the fact that it will give better control of the front distribution.

The apparatus used in this experiment is shown in **Fig. 3-1** (ch. 3). The core was placed in a beaker, which was connected to a scale. The scale was connected to a computer which logged the weight every 10 s throughout the experiment. This way it was possible to monitor how fast IsoparL infiltrated the cores. Immediately after the core came in contact with IsoparL, the logging started.

The glass bowl containing IsoparL was covered with aluminum foil, to prevent it from evaporating and alter the experiment.

When the core comes in contact with IsoparL capillary forces will suck the IsoparL into the core. This will happen spontaneously, hence spontaneous imbibition. It took around 1 hr for the IsoparL to imbibe into the cores. It was observed that during the first 10 minutes the weight increased rapidly, and that actually most of the spontaneous imbibition happened during this time. This makes it extremely important to start the experiment exactly when the core comes in contact with IsoparL. This indicates that the IsoparL infiltrates the core with a high rate in the beginning, and decreases as the imbibition continues.

The resulting graph of a spontaneous imbibition experiment with weight of the core on y-axis and time on x-axis, would be a steep slope in the beginning with a sudden shift of slope after a while. A graph representing every core is presented in **Fig. 6-4** in results (ch 6.4), while a graph for every core is presented in Appendix B. It could be observed that after roughly one hour there would be a clear shift of the slope. At this point the slope decreased dramatically. This point is called the Apex. The Apex indicates where spontaneously imbibition ends. The further slowly increase in weight is caused by diffusion of gas into IsoparL. This happens when equilibrium is not reached between gas and IsoparL. As long as IsoparL is not fully saturated with gas, gas will diffuse into the oil phase.

The average spontaneous imbibition rate is found by estimating the slope in the beginning of the plot. The resulting rates are presented in **Table 6-4** in results (ch. 6.4). See Appendix B for calculations.

The cores were weighed before and after the experiment, and trapped gas saturation could be calculated based on these data by using Eq. 5-14 – 5-16.

$$V_{IsoparL,imbibed} = \frac{W_{core,after} - W_{core,before}}{\rho_{IsoparL}} \tag{B -14}$$

$$V_{gas} = V_{gas,beforeimbibition} - V_{IsoparL,imbibed} \tag{B -15}$$

$$S_{gr} = \frac{V_{gas}}{PV} \tag{B -16}$$

The resulting trapped gas saturations for the cores can be found in **Table 6-5** in results.

5.6 Unsteady-state water flood (USS)

The cores are placed in a rig where injection rate of IsoparL can be controlled by a pump. Several experiments with different rates were executed. The objective was to see how residual gas saturation changes with rate. It was also desirable to find connections between S_{gr} and porosity, permeability and initial saturations. Every experiment was run at the condition of $\Delta P > 0$.

The apparatus for these experiments are presented in **Fig. 5-3.**

5.6.1 Preparations

Before starting the experiment, the cores were installed in coreholders, with a sleeve pressure of 30 bar. This was done to prevent sleeve oil from leaking through the sleeve and come in contact with the core. The sleeve oil used is marcol. This oil is a bit thicker than IsoparL and its fluid properties at 24°C are:

$$\rho_{marcol} = 0,84455 g/ml$$
$$\mu_{marcol} = 23,4 cp$$

5.6.2 Procedure of the experiment

This experiment was performed on a rig as illustrated in **Fig. 5-3.** The analysis described herein was performed at ambient temperature conditions using a system line pressure of 20 bar. The system pressure was applied to improve control of two system properties: nitrogen compressibility and the equilibrium between nitrogen and synthetic formation oil (SFO).

During loading procedure it was important to ensure that the system pressure was carefully applied, equilibrium was established between the nitrogen and SFO, and the system was pressure tested to ensure it was leak tight.

The following process is a general description, used on each core plug to load the system:

1. The core holder was placed vertically into the rig and connected to the flow lines.
2. The production line (to the separator) was displaced with nitrogen, to remove any water left from previous analyses.
3. Nitrogen pressure was slowly applied from the top into the core holder so that the system pressure in the core would be equal to the test pressure to be used. This was done by slowly opening the production valve V4.
4. Valve V4 was closed to shut in the core again.
5. The bypass valve (V3) was opened and the system flooded using bypass line with the SFO. This process was performed at a high rate (minimum 300ml/h) for at least 3 hours to ensure that the nitrogen and SFO were equilibrated at the test pressure: i.e. SFO becomes completely gas saturated and gas is completely humidified.
6. The system pressure should not change by more than 1% to ensure that the system is tight and contains no leakages. So the system pressure was constantly monitored during the stabilization period.
7. After 3 hours the bypass valve (V3) was closed.
8. The production line was displaced with nitrogen to remove the SFO prior to oil injection.
   a. This was performed to reduce dead volumes for mass balance calculations.
   b. It was performed by slightly cracking the sealing nut of the production valve (V4) – ensuring that the system pressure was not affected – and allowing oil to be produced through the opening, until no further oil was produced from the production line.
   c. The nut was resealed and checked for leakedge.
9. Next step was to open the core to the system: this was performed to ensure that there was no possibility of injection into the core
   a. Opened valve V4 to allow gas into the core.
   b. Closed V4
   c. Opened bypass valve (V3) to ensure equal pressure up and down stream
   d. Closed V3 and opened V4 & V2.

When all these steps of preparation had been executed, the experiment of obtaining trapped gas saturation could begin. The graduated separator (see Fig.6) contains IsoparL which will be injected into the core, while gas will assemble on the top. IsoparL was injected into the core with constant line pressure, temperature and rate. Pressure difference, temperature and liquid type was measured while connected to a computer. The data would result in 3 graphs on the same plot. The data were plotted against time.

A fluid sensor was placed at the producing end of the core, and reacted when it was breakthrough. This was shown by a shift on the graph.

A camera was installed to capture the burette every 5 min, for it to be possible to see how gas was produced with time. As the experiments go, the value of oil in the burette will decrease, since it is being injected into the core. When the experiment was finished the images needed to be analyzed and form a production graph.

After breakthrough the core would be flooded for at least 1 PV. In total it was maximum injected 2 PV. This was done to stabilize the process.

Trapped gas saturation can be found by two different methods. The first method is using the weight difference. By weighing the cores before and after the experiment it is possible to calculate residual gas saturation. The second method is to read the produced gas volume at breakthrough from the burette.

Differential pressure must usually be time offset corrected for inlet dead volumes, whereas production of gas must be corrected for volume and for total time offset (dead volumes + production line). An excel spread sheet was used, where all these factors were corrected.

The obtained residual gas saturation is presented in **Table 6-6** in results.

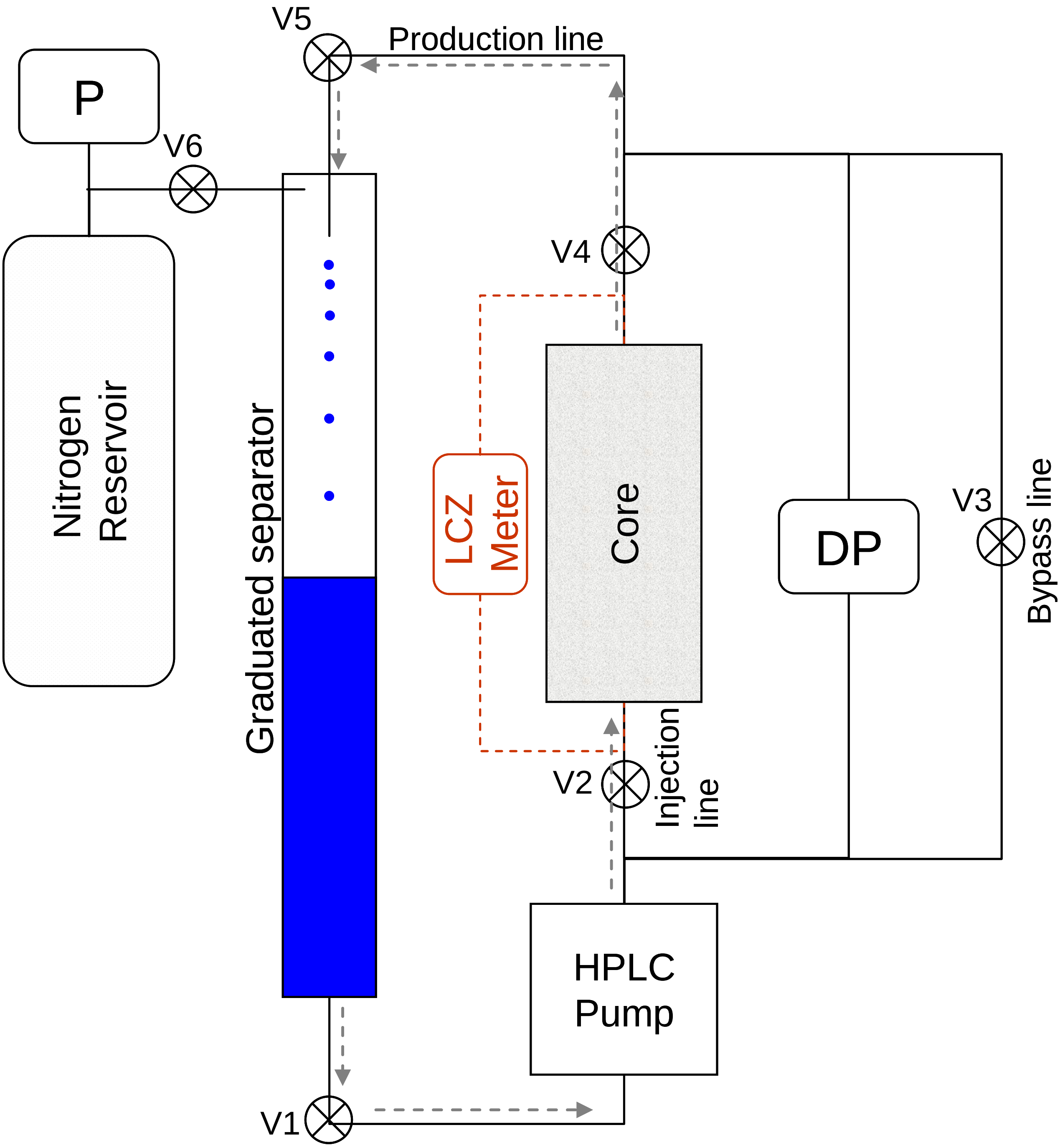


Fig. 5 - 3 - Schematic of the USS trapped gas apparatus

V1 = lower separator valve

V2 = injection valve

V3 = bypass valve

V4 = production valve

V5 = upper separator valve

V6 = gas reservoir valve

5.6.3 Liquid injection when ΔP>0

The objective for this experiment was to find the amount of trapped gas, when IsoparL was injected into the core with a constant rate. A desirable goal was to figure out how residual gas saturation changes when rate increases. The first rate used was 4ml/h which is equal to 1 ft/day which is what is normally used in the reservoir.

After this experiment had been executed for every core the experiment was repeated with higher rates. This resulted in a total of 3-4 measurements for every core. All these experiments were executed at the condition of $\Delta P > 0$. Since IsoparL was used as the wetting phase, the capillary forces would not exceed the viscous forces, and there would be no spontaneous imbibition, which would have led to $\Delta P < 0$.

The resulting graph for every core is presented in **Fig. 6-5** in results. It can be observed a general trend of S_{gr} decreasing as rate increases.

5.6.3.1 *Rate = 4 ml/h*

In general it took around 90 min to get breakthrough when rate was set to 4 ml/h. When breakthrough was reached, 1 PV of IsoparL was injected. Since all the cores had a PV around 12 ml, the total time of the experiment would be about 4h 30 min.

The result would be a plot with two graphs. One for gas produced and one for ΔP, both plotted against IsoparL volume injected, see **Figs. C-1 – C-42** in Appendix C. The pressure difference will normally increase rapidly in the beginning. When breakthrough is reached the pressure difference will be stabilized for than to slowly decrease. It was observed that maximum ΔP varied for every sample. It was clear that the cores with the highest permeability had the smallest maximum ΔP. This is logical when studying Darcy's law, see Eq. 5-17.

The gas production graph will increase on a linear line until breakthrough, for than to keep slowly increasing.

$$\Delta P = \frac{Q\mu_{IsoparL}L}{k_{IsoparL}A} \qquad \text{(B -17)}$$

Where

Q = Injection rate of IsoparL

$\mu_{IsoparL}$ = viscosity of IsoparL

$k_{IsoparL}$ = permeability of IsoparL

A = cross sectional area of the plug

L = length of core that has been infiltrated by IsoparL

When breakthrough has been reached no more gas will be produced, and the pressure difference will stabilize.

The resulting residual gas saturation can be found in **Table 6-6** in results.

5.6.3.2 Rate = 10-50 ml/h

When executing experiments with such high rate as 10-50 ml/h it would take much shorter time for IsoparL to reach breakthrough. On average it took around 15-20 min.

By rewriting Darcy's law you get that differential pressure increases as rate increases, see Eq 5-17.

Every other variable is constant, the cores have a constant area and length, and the fluids have the same permeability and viscosity. So the pressure will increase proportional with rate.

From Darcy's law it is clear that delta P increases as permeability decreases, see Eq. 5-17. Since the cores had different permeabilities this was examined while executing the experiments.

It was important to adjust the pump so it could bear high pressures, since it might get pretty high, when injection rate is increased from 4 ml/h to 50 ml/h.

The same plots as for the low rate case is made for these rates, and are shown in **Figs()** in Appendix B**.** The different rates and the resulting residual gas saturation can be found in **Table 6-6** in results.

5.6.4 Trends

When it is desirable to find how one variable effects the residual gas saturation, it is important to keep every other factor constant. The main focus in this study is to see how residual gas saturation varies with rate. It is also desirable to find a trend between residual gas saturation and porosity, permeability and initial saturation.

5.6.4.1 Rate

When all the experiments were executed, the aim was to find a trend for residual gas saturation when using different rates. This is done by finding residual gas saturation for each core at different rates, and then comparing the results and see if each core shows the same trend. The ultimate goal is to see if residual gas saturation increases or decreases with an increase in rate. This is plotted in **Fig. 6-5** in results.

!! All the gas production graphs are placed in Appendix B. By looking at **Figs. B-1 – B-26** it is clear that the gas production happens before breakthrough and that it follows a linear line. The breakthrough is clearly indicated by a shift of the slope. After breakthrough almost no more gas is produced, and the slope is almost zero. By studying all the graphs it is observed that the higher the rate, the faster the production of gas.

The differential pressure profile is typically increasing rapidly until breakthrough, for than to decrease slowly. This can be observed on almost every graph. The value of the maximum differential pressure is dependent on rate and permeability of the core. It is observed that the higher the rate the higher pressure difference, and the lower permeability the higher pressure difference.

The variation of residual gas saturation with rate is plotted in Fig. 6-5**.** Here all cores are plotted on one graph to see if they show the same trend.

5.6.4.2 Porosity

To be able to discover a trend between porosity and residual gas saturation it is important to choose cores with the same initial saturations, and to use the same rate. By looking at the initial saturations of the cores used in this study, it was clear that Berea 1, Berea 2 and Berea 3 have very similar initial saturations. (see table 3) So these cores were chosen for finding a trend between porosity and residual gas saturation. The rate used for illustrating this trend is 4 ml/h. The resulting graph is shown in **Fig. 6-7** in results.

5.6.4.3 Permeability

For being able to discover a trend between permeability and residual gas saturation it is important to choose cores with the same initial saturations, and to use the same rate. So the same cores used in finding a trend for porosity is used (Berea 1, Berea 2 and Berea 3). The rate used for illustrating this trend is 4 ml/h. The resulting graph is presented in **Fig. 6-8**, in results.

5.6.4.3 Initial saturation

When studying how initial saturation affects the residual gas saturation, it was important to use cores with similar porosity and permeabilities values, since initial saturation should be the only factor varying. The cores Berea 1, Berea 2, Berea 3 and N-108 similar porosity and permeability values (see table 3), so it was decided to compare these samples. The resulting residual gas saturation was compared when Q = 4 ml/h.

The resulting graph is presented in **Fig. 6-9.**

6 Results

6.1 Rock properties

Three of seven cores received from Statoil were chosen for further studies. **Fig. 6-1** shows a porosity-permeability plot. Three cores were chosen by studying this plot.

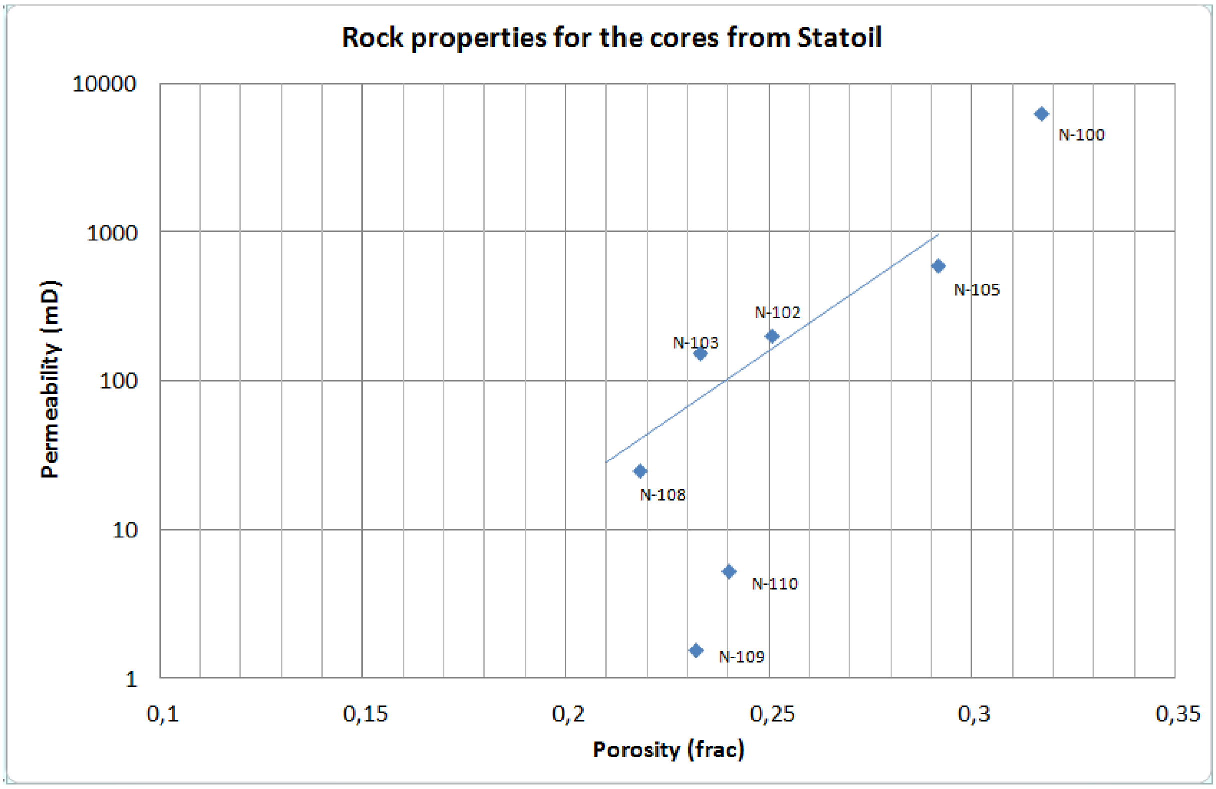


Fig. 6 - 1– Porosity-permeability graph for deciding which cores to use

The rock properties for every core are presented in **Table 6-1.**

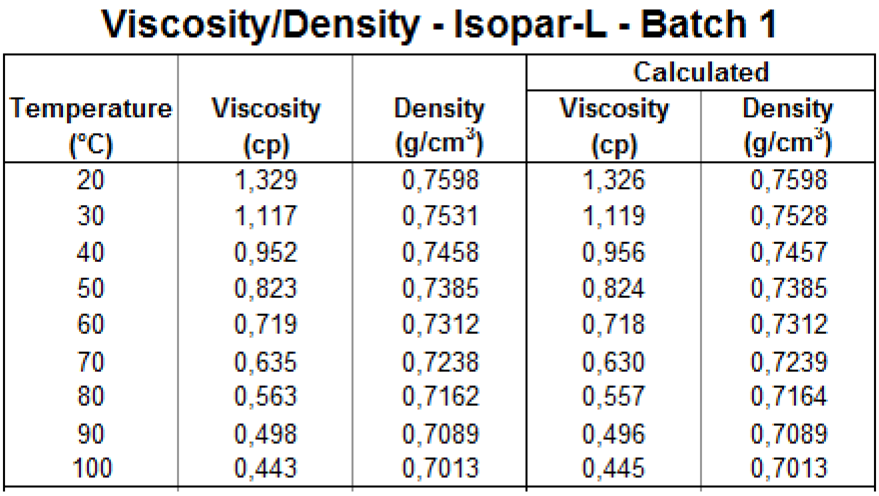
Table 6 - 1- Rock properties

Core ID	Length (cm)	Diameter (cm)	Pore Volume (cm^3)	Porosity (%)	Permeability (mD)	IsoparL permeability (mD)	Dry weight (g)
Berea-1	4.72	3.79	8.73	16.4	56.15	52.15	118.00
Berea-2	4.74	3.81	9.48	17.5	44.15	41.77	118.48
Berea-3	4.69	3.81	9.80	18.3	56.38	52.45	116.16
N-102	4.81	3.80	12.07	25.1	201.10	177.26	108.66
N-105	4.80	3.76	13.92	29.2	592.81	584.31	99.45
N-108	4.85	3.77	10.73	21.8	24.76	18.41	112.04

6.2 Fluid properties

In this thesis IsoparL and air has been the fluids used to saturate the core. IsoparL is a light colorless oil while air is a gas. For both IsoparL and air the density and viscosity are dependent on temperature. The viscosity and density data for IsoparL is presented in **Table 6-2**, while the density data for air is presented in **Fig. 6-3**, and viscosity data in **Fig. 6-3**.

Table 6 - 2 - Properties for Isopar L

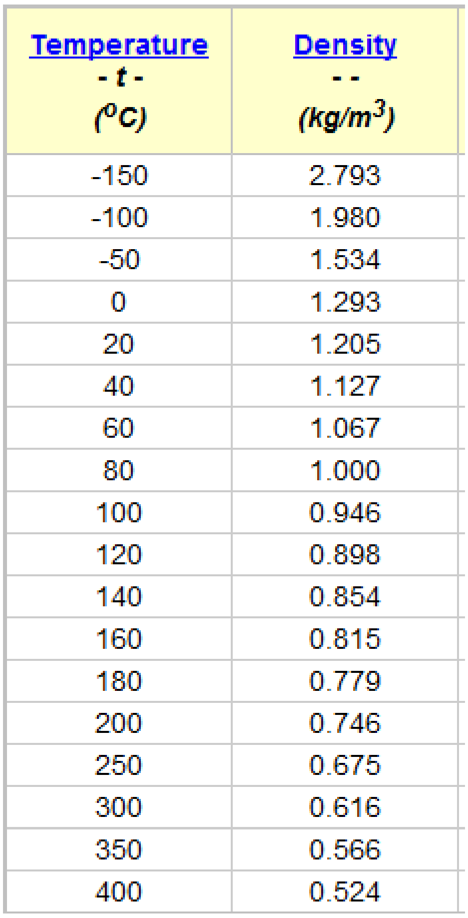


Viscosity/Density - Isopar-L - Batch 1

			Calculated	
Temperature (°C)	Viscosity (cp)	Density (g/cm^3)	Viscosity (cp)	Density (g/cm^3)
20	1,329	0,7598	1,326	0,7598
30	1,117	0,7531	1,119	0,7528
40	0,952	0,7458	0,956	0,7457
50	0,823	0,7385	0,824	0,7385
60	0,719	0,7312	0,718	0,7312
70	0,635	0,7238	0,630	0,7239
80	0,563	0,7162	0,557	0,7164
90	0,498	0,7089	0,496	0,7089
100	0,443	0,7013	0,445	0,7013

The average temperature throughout all my experiments was 25 °C. At this temperature the IsoparL density will be 0.757 g/ml and the air density will be 0.0012 g/ml. Density is an important factor in this thesis, since it was desirable to find volumes of IsoparL and air in the pores calculated from weights.

Table 6 - 3 - Different densities for air (The engineering toolbox)



Temperature - *t* - (°C)	Density - - (kg/m^3)
-150	2.793
-100	1.980
-50	1.534
0	1.293
20	1.205
40	1.127
60	1.067
80	1.000
100	0.946
120	0.898
140	0.854
160	0.815
180	0.779
200	0.746
250	0.675
300	0.616
350	0.566
400	0.524

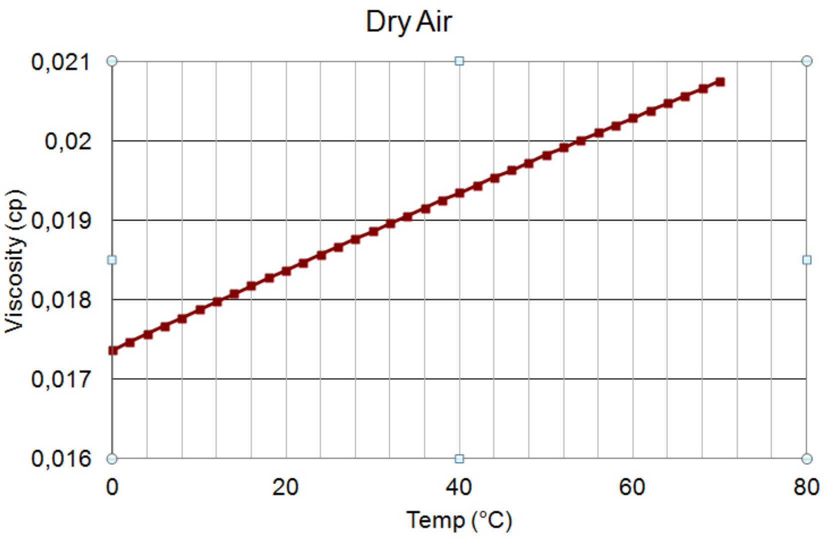


Fig. 6 - 2 - Different viscosities for dry air kilde

6.3 Initial saturations

The resulting initial saturations by using the same centrifuge with the same rate over the same amount of time are presented in **Table 6-3.**

Table 6 - 4 - Initial IsoparL saturations

	Initial saturations				
Plug ID	S_{oi}				
	Spontaneously imbibition	Q = 4 ml/h	ΔP = 0	ΔP > 0	ΔP > 0
Berea 1	0,12	0,11	0,20	0,16	0,15
Berea 2	0,11	0,11	0,16	0,12	0,13
Berea 3	0,09	0,10	0,11	0,11	0,10
N-102	0,21	0,27	0,21	0,19	
N-105	0,17	0,17	0,13	0,14	
N-108	0,30	0,37	0,32	0,31	

6.4 Spontaneous Imbibition

The resulting imbibed IsoparL graph for every core is shown in **Fig. 6-4**. The steep curve in the beginning represent the gas replacement by imbibition, while the slowly increase in volume of IsoparL at the end of the graph is caused by diffusion. Gas will diffuse into unsaturated IsoparL.

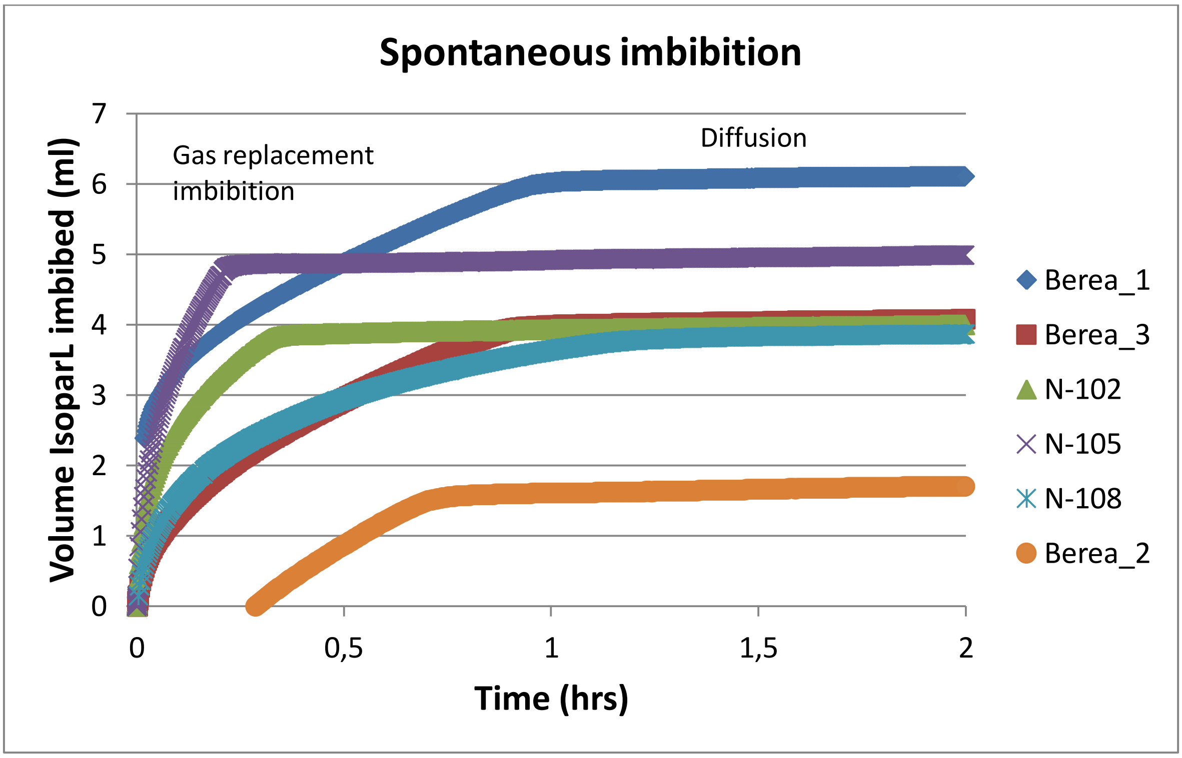


Fig. 6 - 3 - Spontaneously imbibed IsoparL graph for every core

The average spontaneous imbibition rate was found by calculating the slope of the IsoparL-injected graph. The IsoparL volume imbibed graph for every core is found in Appendix B. The resulting average rate is presented in **Table 6-4.**

Table 6 - 5- Calculated average spontaneous imbibition rate for every core

Plug ID	Average rate (Q)
	(ml/h)
Berea 1	2,93
Berea 2	3,7
Berea 3	3,2
N-102	8,6
N-105	16,7
N-108	2,08

By weighing the core samples before and after the spontaneous imbibition experiment, it was possible to calculate the residual gas saturation. The resulting values are presented in **Table 6-5**.

Table 6 - 6- Residual gas saturation from spontaneous imbibition

Residual gas saturation (from weights)	
Plug ID	S_{gr}
	Spontaneously imbibition
Berea 1	0,23
Berea 2	0,40
Berea 3	0,36
N-102	0,26
N-105	0,28
N-108	0,17

6.5 USS

For every experiment a pressure, produced gas and gas saturation curve were produced. Two graphs for every core at every rate are presented in Appendix C.

The resulting S_{gr} for the USS experiments at breakthrough is presented in **Table 6 – 6**.

Table 6 - 7 - Residual gas saturation with different rates

Residual gas saturation at breakthrough (from rig)				
Plug ID	S_{gr}			
	Q = 4 ml/h	ΔP = 0	ΔP > 0	ΔP > 0
Berea 1	0,54	0,45	0,43	0,39
Berea 2	0,58	0,50	0,50	0,54
Berea 3	0,60	0,52	0,49	0,36
N-102	0,46	0,31	0,42	
N-105	0,44	0,46	0,47	
N-108	0,43	0,37	0,31	

S_{gr} at the end of every experiment was also calculated, but it was chosen to not use these results. These data are presented in **Table D-4** in Appendix D.

To see how rate affects residual gas saturation, a plot of S_{gr} and rate was made. In **Fig. 6--5** all six cores are represented. This way it is easy to see if there is a clear trend. In this graph only the resulting S_{gr} from the USS experiment are presented.

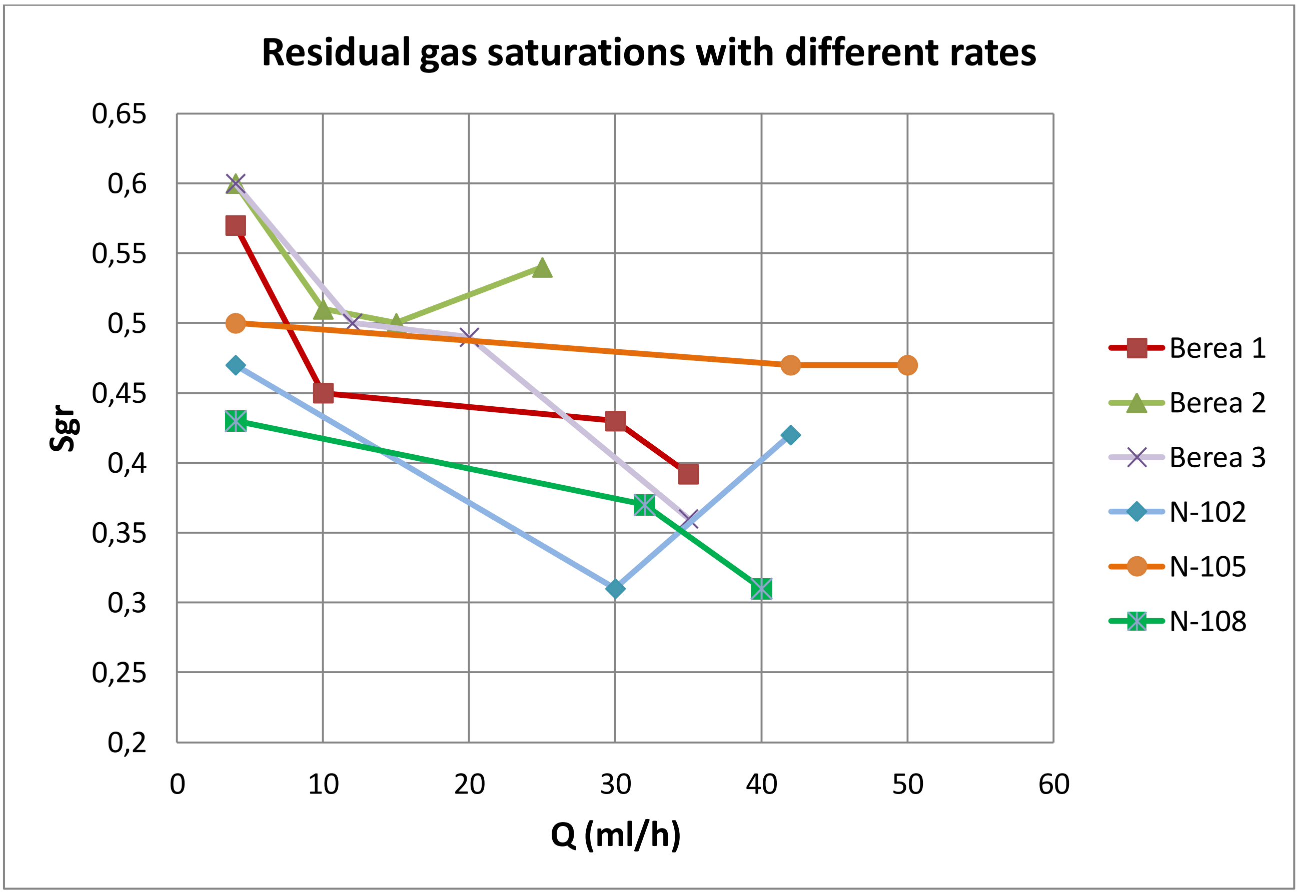


Fig. 6 - 4 - Resulting Sgr for every core

By studying Fig. 6-5 it is clear that the general trend is that S_{gr} decreases as rate increases. Samples Berea 2 and N-102 shows some abnormalities. S_{gr} at the highest rates for these cores are suddenly higher than previous measurements with lower rate. These points are not following the general trend.

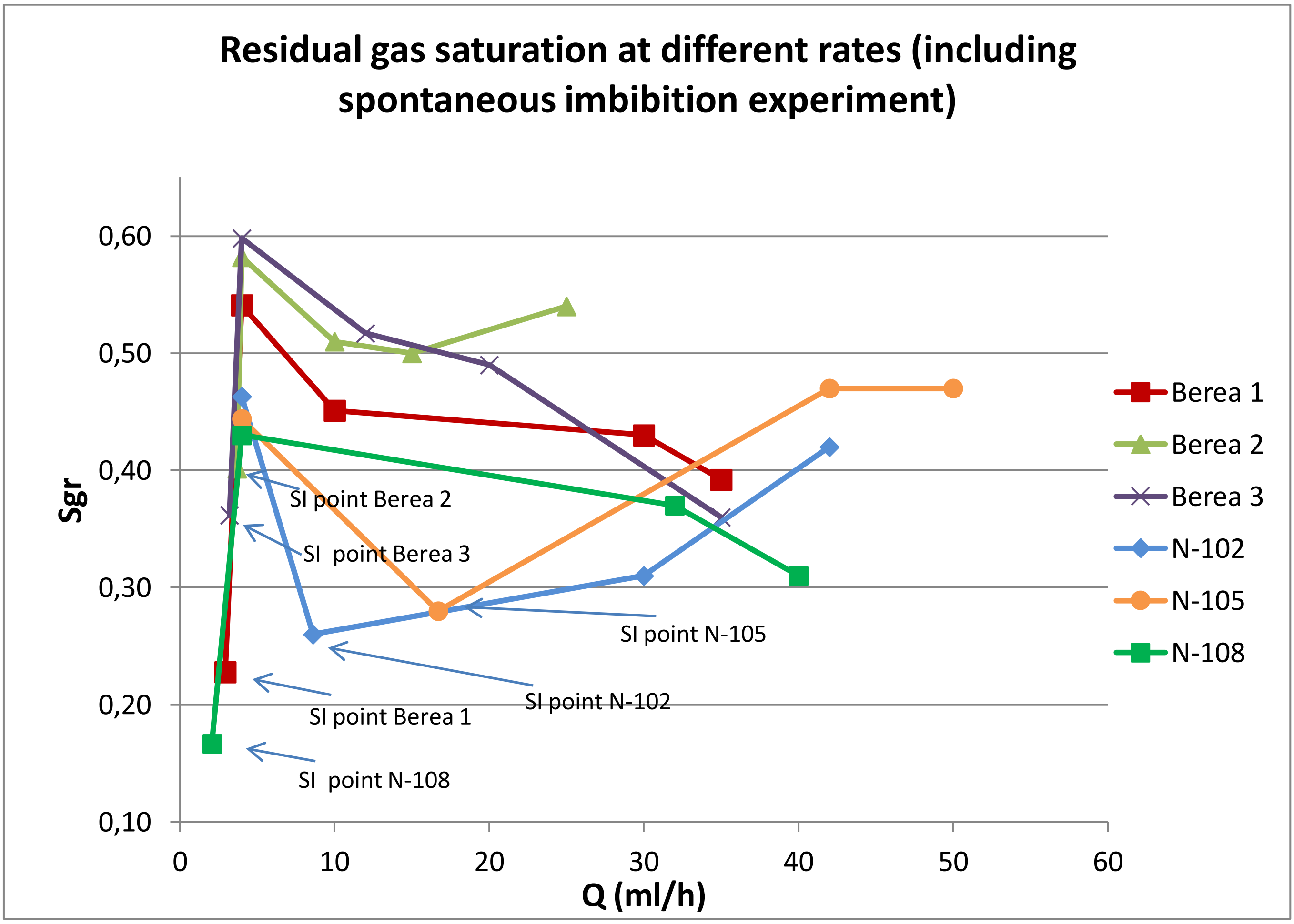


Fig. 6 - 5 - Resulting Sgr for every core including the spontaneous imbibition experiment

It was also interesting to compare the resulting S_{gr} from the USS experiments with the results from the spontaneous imbibition experiment. This is done in **Fig. 6-6**. Here the SI point stands for the spontaneous imbibition point. It is clear that in general the spontaneous imbibition rate was lower than 4 ml/h, but for cores N-102 and N-105 it was a bit higher.

The graph shows that in spontaneous imbibition gives the lowest S_{gr}.

6.6 Trends

6.6.1 Porosity

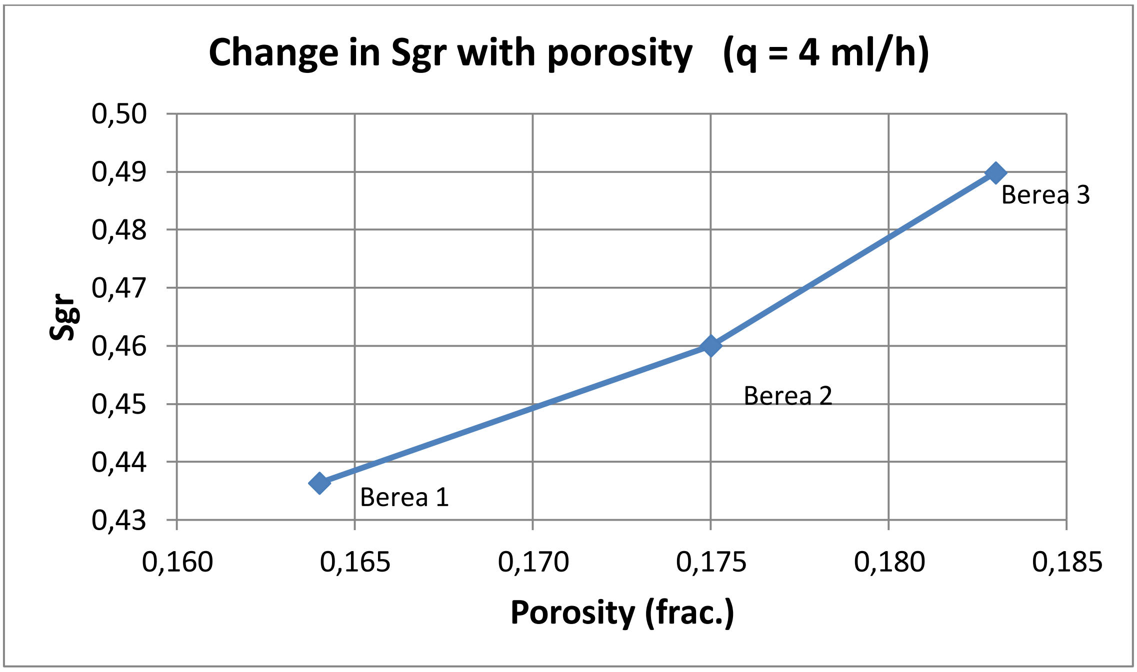


Fig. 6 - 6 - Effect of porosity on Sgr

Fig. 6-7 gives a clear indication that residual gas saturation increases as porosity increases. This was the result for every rate used and for the spontaneous imbibition experiment.

6.6.2 Permeability

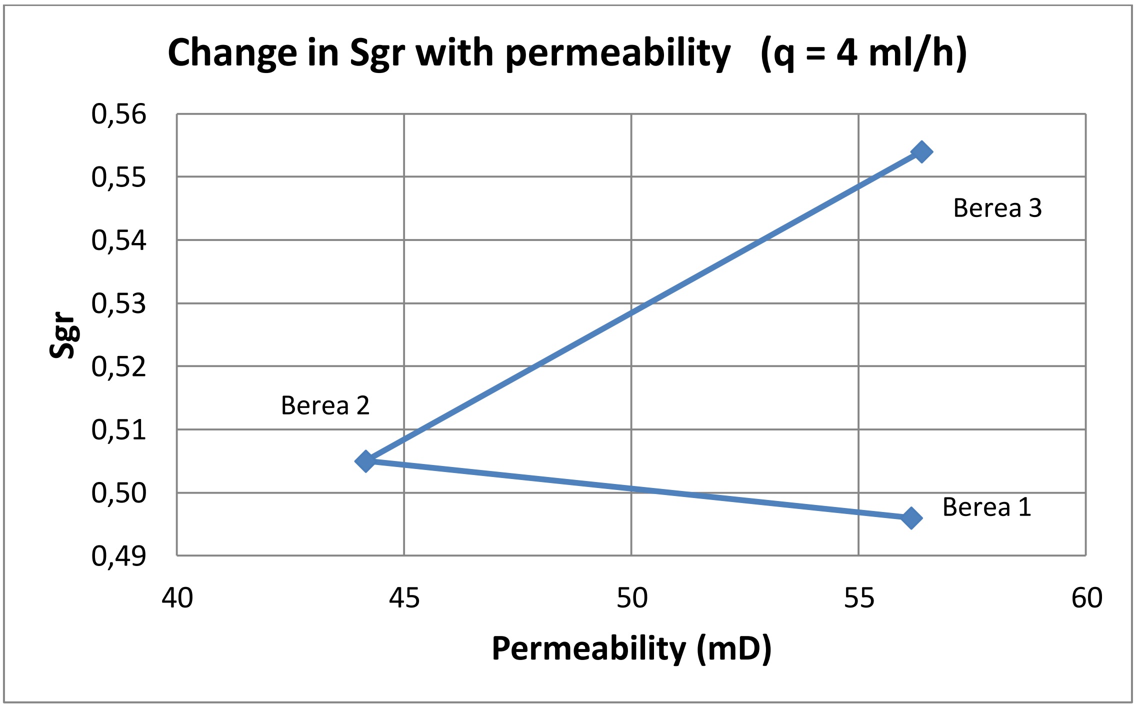


Fig. 6 - 7 - Effect of permeability on Sgr

By looking at **Fig. 6-8**, no trend can be observed. That means that this study cannot conclude with any trend for how permeability affects residual gas saturation. This graph is representative for every rate including the spontaneously imbibition experiment.

6.6.3 Initial saturation

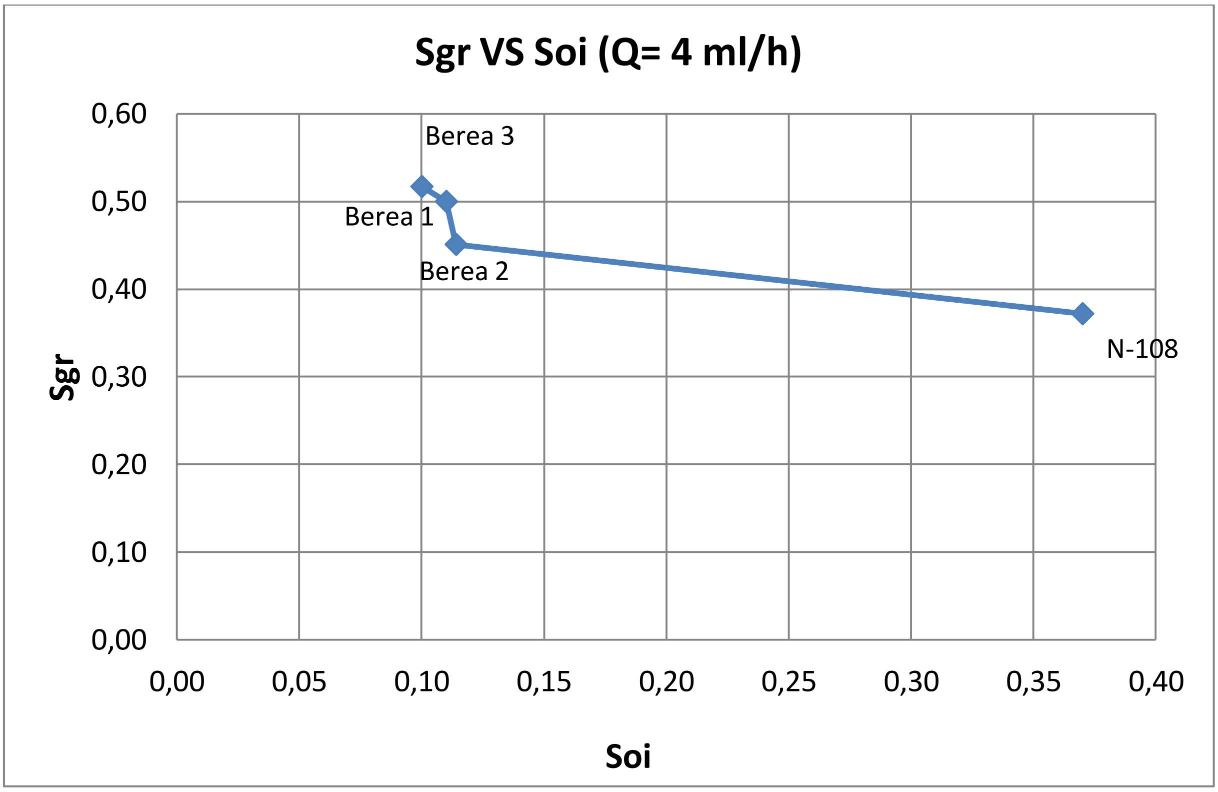


Fig. 6 - 8 - A graph showing how initial IsoparL saturation affects S_{gr}

It is clear by looking at **Fig. 6-9** that S_{gr} decreases as initial IsoparL saturation increases. This result was the same for every rate and for spontaneous imbibition.

7 Discussion

7.1 Capillary and Viscous forces

The initial idea when starting this master thesis was to execute USS experiments and compare S_{gr} for different rates when $\Delta P < 0$, $\Delta P = 0$ and $\Delta P > 0$ at the beginning of the experiment. It was also desirable to execute spontaneous imbibition experiments.

When $\Delta P < 0$ at the start the rate created by the pump would be smaller than the spontaneous imbibition rate. That means that the capillary forces will be greater than the viscous forces in the beginning of the experiment. So for this case spontaneous imbibition will happen in the beginning, and then when the capillary forces weakens and the spontaneous imbibition rate decreases the viscous forces will dominate and the rate set to the pump will be the rate going through the core.

When $\Delta P = 0$ at the beginning of the experiment the rate created by the pump would be equal to the spontaneous imbibition rate. It would be very interesting to see how this would affect the residual gas saturation. It is not well documented what would actually happen in the core for this case. The capillary forces would be equally strong as the viscous forces, so maybe the wetting phase will be injected with a high rate and result in the wetting fluid being able to infiltrate more pores. Maybe the capillary forces do not decrease in strength, but is kept high due to viscous forces. If this happens S_{gr} will probably be low which is desirable. The scenario where $\Delta P = 0$ might also poor S_{gr} results, maybe the flow will be unstable and less gas will be recovered. It was desirable to be able to answer some of these questions.

When $\Delta P > 0$ at the beginning of the experiment the rate created by the pump would exceed the spontaneous imbibition rate. This means that there would be one front with one rate throughout the flooding of the core.

This master thesis was supposed to compare these scenarios and see how they affected $S_{gr.}$ This did not happen.

7.1.1 Discovering the problem

It was expected to see different trends on the pressure graph for the 3 cases of $\Delta P < 0$, $\Delta P = 0$ and $\Delta P > 0$. This assumption was based on previous experiment where water was used as the wetting phase. In the case of $\Delta P < 0$; the pressure difference graph was suppose to decrease in the beginning to a more and more negative pressure, for than to start increasing when viscous forces got dominating. In the case of $\Delta P = 0$; the pressure difference graph was suppose to start at zero for than to increase. In the case of $\Delta P > 0$; the pressure difference graph was suppose to start at a positive value and just keep increasing until breakthrough.

When this did not happen it made me realize that maybe IsoparL was not the right fluid to use. Weatherford laboratories had used IsoparL as wetting fluid in previous spontaneous imbibition experiments, and had great success with it. On the basis of that observation it was assumed that it would work perfectly with IsoparL as wetting fluid in USS experiments as well. This turned out to be wrong. It was also convenient reasons for using IsoparL as wetting fluid. It would not evaporate as much as water, and hence alter the experiments less. It would also be easier to establish initial saturations between every experiment.

When using water as a wetting phase, the IFT is large, around 72 mN/m and this is a strong capillary force that will pull the water in to the core faster than the pump can pump it in (4 ml/h). In these experiments it has been clear that the pressure has decreased in the beginning when capillary forces excides the viscous forces. And then when the pump is pushing the water in and not the capillary forces that drag it in, the pressure will increase. So a main goal for this experiment was to see what would happen if the pump was pushing right from the start.

Oil and gas will have much lower IFT. It will be approximate 25 mN/m. This is about a third of the IFT between water and gas. That implies that the capillary forces will not be as strong, and the rock will not attract the oil as fast as with water. In reality this will result in a lower imbibition rate for IsoparL than for water. The imbibition rate turned out to be lower than 4 ml/h for almost every core, which will give USS results in the region of $\Delta P > 0$.

In principle this thesis did not get the desirable results. But the results obtained will be discussed further in this chapter.

7.2 Results

7.2.1 Initial saturation

There are different methods for obtaining initial saturations in a core sample. A centrifuge and evaporation are two methods that were relevant to use in this master thesis.

During the process of evaporation, the cores are placed in an incubator with high temperature (60-80 °C). This is done to make the IsoparL evaporate quickly. When doing this it is important to weight the cores often to get the desirable initial saturations of air and IsoparL. When desirable weight of the cores is reached, they need to be wrapped in aluminum foil to prevent further evaporation. When executing this method, the gas will be located in the middle of the core, since IsoparL evaporate inwards through the core. This method is also quite time consuming. It can take up to 5 days for initial saturation to be reached, and there is need for constant monitoring

In the process of using a centrifuge, air are pushed into the core creating a drainage process. When using a centrifuge the gas will be evenly spread out throughout the core. This distribution is more desirable when executing residual gas experiments. By using this method the process is more controlled, since the experiments will have same RPM and will be executed for the same amount of time. Even though the same routine is used every time it is still a chance that the initial saturations will vary a bit. This is natural, since there will always be some uncertainties with any lab experiment. As long as the results are kept within a reasonable error it is a good method.

In this study a centrifuge was used to drive the fluids to initial saturation. The reason for this decision was that it is difficult to know if the gas has the same distribution if using evaporation method. It is more certain if using a centrifuge. Another important factor is that it is more desirable to have the gas evenly spread out than concentrated in the middle of the core. It is also positive that the centrifuge method is less time consuming then the evaporation method.

The only way of controlling what fluid is in the core after every procedure is to weigh the cores. By weighing the cores before and after it has been in the centrifuge it is possible to calculate the initial saturations. It was observed some different resulting initial saturation after the centrifuge. Most were within reasonable error margin. If the initial IsoparL saturation was too high, it was possible to use evaporation to get more reasonable saturations. If the initial IsoparL saturation was to low compared to earlier results, there was not much to do, but fortunately this was not a problem in this thesis.

7.2.2 Spontaneous imbibition

By looking at **Fig. 6-4** it is clear that IsoparL will be sucked into the core by capillary forces quickly in the beginning, which is represented by the steep curve. After a while the capillary forces will diminish and the spontaneous imbibition process will stop. When looking at the graph is clear that the volume of IsoparL is increasing slowly after the imbibition process. This is due to diffusion of gas into IsoparL. As long as the two fluids are not in equilibrium, air will continue to saturate IsoparL.

S_{gr} is calculated by weighing the cores before and after the spontaneous imbibition process. So the resulting S_{gr} represent both displaced and diffused gas.

By calculating the slope of the steep part of the imbibition curve you will find the spontaneous imbibition rate. These values are presented in **Table 6-4.** The calculations are presented in Appendix B. It is clear that most of these rates are below 4 ml/h which was the lowest rate used in the USS experiments. The spontaneous imbibition rates obtained are very low. This is due to the fact that IsoparL and not water is used as the wetting phase. If water had been the wetting fluid, the rate would be significant higher, due to stronger capillary forces.

By comparing S_{gr} with the rate it is clear that S_{gr} increase as rate increase. I have excluded core N-102 and N-105 from this comparison. The rates obtained for these cores are higher than 4 ml/h. This was a bit surprising since no negative pressure were observed at the USS experiment with rate equal to 4 ml/h. These two cores have a bit higher permeability than the other cores both have permeability higher than 200 mD, while the rest have permeabilities below 60 mD. The high rate is probably a result of these high permeabilities. It still does not explain why it did not give negative pressure in the USS experiment.

7.2.3 USS method

The resulting S_{gr} from the USS experiment could be found in two different ways. Either by weighing the core before and after the experiment or by reading injected IsoparL from Burette. Both of these procedures were executed in this study. They did not show the same results, it was in the same region but not completely the same. The reason for this can be small uncertainties on every step of the process. Another reason is that the results obtained from the burette are at breakthrough while the weight results might include some extra production of gas as a result of diffusion. When comparing the results from the weights (Appendix D) and the burette (Table 6-6) it is clear that S_{gr} calculated from the weight difference show a lower value. The measurements from the burette gave the most plausible results, so it was chosen to use S_{gr} by the burette value.

The resulting gas produced curve is a increasing rapidly in the beginning, the higher the rate the faster it will increase. When breakthrough occurs, it will show as an apex on the curve. After breakthrough the curve will either increase very slowly or keep the produced gas value at breakthrough throughout the rest of the experiment. If it increases a bit it is probably due to diffusion of gas into IsoparL.

By studying the figures in Appendix C it is clear that the pressure profile look almost the same for every experiment. It will start at zero and increase rapidly until breakthrough is reached and will then decrease slowly. The reason for this decrease in pressure difference is diffusion of gas into IsoparL. It can also be observed that the higher the rate the higher the maximum pressure. By studying Darcy's law this is a natural effect. Even though the pressure difference is increasing with rate, it is still only in the range of kPa, which are very small pressures. When pressure difference is this small capillary forces do play an important part. By looking at cores at the same rate but with different permeabilities (Berea 3, N-

102,N-105 and N-108) it is clear that the maximum pressure value increases as permeability decreases. This is logical when studying Darcy's law, see Eq. 5-17. For instance the core N-105 has a permeability of 592.81 mD and a maximum pressure of 4.6 kPa when Q = 4 ml/h, while the core Berea 3 has a permeability of 56.38 mD and a maximum pressure of 20 kPa.

7.2.4 Trends - rate, porosity, permeability, initial saturation

When looking at **Fig. 6-5** where all the cores are presented, the general trend is that S_{gr} decreases as rate increases for a forced imbibition experiment done in a USS rig as presented in **Fig. 5-3**. By studying the graphs closely it can be observed that some cores yields from the main trend. The reason for this is unclear, but when executing work in the lab there are many potential sources of error. It might be caused by instabilities in the rig or alterations of the core. The trend that S_{gr} decreases as rate increases when executing USS experiments with IsoparL as wetting phase are logical. This is because as rate increases pressure difference increases, which will make the IsoparL infiltrate more pores. If I had been studying S_{gr} for rates lower than 4 ml/h, it is possible that that S_{gr} would increase as rate increases. That is due to the fact that there would be spontaneous imbibition at the beginning of the experiment.

By looking at **Fig. 6-6** where S_{gr} for spontaneous imbibition is included it is clear that spontaneous imbibition gives a better recovery of gas than USS method. This is a bit strange since the spontaneous imbibition rate was the lowest rate. An explanation for this might be that capillary forces will make IsoparL infiltrate more pores than viscous forces, and hence produce more gas.

It was desirable to find a connection between porosity and S_{gr}. To do this, cores with similar initial saturation was used at the same rate. The 3 Berea cores have very similar initial saturation. So they were studied at Q = 4 ml/h. **Fig. 6-7** shows that an increase in porosity will give an increase in S_{gr}. This is in agreement with previous research executed by other scientists. Legatski *et al.* (1964) and Suzanne *et al.* (2003) found that S_{gr} increases as porosity increases.

An attempt to find a trend between permeability and S_{gr} was made. By looking at **Fig. 6-8** it is clear that this attempt failed, it was not possible to find a general trend. Studies done by other scientists come to the same conclusion. Legatski *et al.* (1964) did not manage to find a good trend between permeability and S_{gr}.

When trying to find a trend between S_{gr} and initial saturation, the cores Berea 1, Berea 2, Berea 3 and N-108 were chosen due to the fact that they have similar porosity and permeability values. By looking at **Fig. 6-9** it is clear that a trend between initial IsoparL saturation and S_{gr} exists. My results show that S_{gr} decrease as S_{oi} increases. According to Firoozababadi *et al.* (1987) and Li and Firoozabadi (2000) this might be a plausible theory.

As always in laboratory work there are a lot of uncertainties, and of course there exist papers that suggest other trends

7.3 Laboratory

7.3.1 What can go wrong?

When working in a lab, there are always a lot of things that can go wrong which might alter the results. There are also a lot of uncertainties when working with reservoir cores. Since it is not possible to look into the cores, you have to rely on weight measurements. In this chapter I will try illustrate every aspect of what can go wrong and might be sources of error in the lab.

It is always a possibility that an instrument may fail. The settings might be incorrect which will give wrong results. So it is always a good idea to evaluate the results, either by comparing with earlier measurements or by thinking logically.

When working in a lab it is always necessary to treat fluids and cores carefully. It is very important to label beakers with the fluid identity. This way every other lab worker will know what fluid you are working with, and they will not use it for wrong purposes.

The use of clean gloves can be a preventer for altering the cores. It is not desirable to get unwanted fluids in contact with the cores. When using gloves, you are protecting the core and your hands from unwanted fluids.

Even though the cores were installed in core-holders by using the same procedure every time, some experiments were ruined by sleeve oil coming in contact with the core. This was discovered when the oil level in the burette increased instead of decreasing when starting the experiment. The reason for this might be that the sleeve contained raptures. To restore the cores when this happened they were flooded with 7 PV of IsoparL to remove all of the marcol. It is not certain that everything was removed. But recording to the weight after flooding, there was not marcol left. This is based on the fact that marcol has a higher density then IsoparL, and the core did not way more than when saturated with only IsoparL.

The biggest source of error is most likely the USS rig. Actually everything can fail with this rig. My experience is to be prepared for every possible thing that can go wrong, because eventually it is going to happen. If anything goes wrong the results cannot be used and the core needs to reestablish initial saturations before it can be placed in the rig again. It is important to always check every vent, pump and coupling for leakage. If either one of them leak the burette value of injected IsoparL will be misleading.

It is important to keep the line pressure at around 20 bar. The Teflon line can only bear 30 bar. If the pressure gets higher than this the Teflon lines will burst and the experiment is ruined. It will also be very time consuming to replace every Teflon line. It is also important to have the same line pressure throughout every experiment, since fluid compaction is dependent on the pressure. Another vital check point is to make sure that there is enough nitrogen on the gas tank. If the nitrogen tank gets empty there will be no line pressure which will definitely alter the experiment. Make sure that every vent that should be open is open, since other people may have tackled with them. Even though the policy should be to leave the rig as it was found, this does not always happened.

It should be compulsory to check that every cell is properly connected. If someone has tackled with the connections the graphs will not show the actual values. It is important that the visual cell work properly, to get a good idea of when breakthrough happens. The lines can be bended which can lead to very unstable results.

It is very important that the camera photographing the burette stands still throughout the whole experiment every time the rig runs. Somebody might run into it, and alter the production reading. The smallest of movement may ruin the pictures completely.

7.3.2 Safety

Safety is always the top priority when working in the lab. I did not work with very dangerous chemicals, but it is always necessary to be proactive. This includes using a lab coat and safety glasses at all times. The lab coat will protect clothes and the safety glasses will prevent eye damaging. It is also important to wear gloves when working with different fluids to protect your skin. IsoparL will dry out the skin if it is in direct contact. When entering a room with high levels of chemicals it is important to use a gas mask to protect your mouth and lungs.

If fluids are spilled on the counter or on the floor, it is wise to clean it up at once, since it might cause slippery floor where someone can slide and hurt themselves.

It is important get proper instructions, before tackling a new job in the lab. This way it is more likely that everything is done correctly, and less chance of anything dangerous happening.

When working with items that are under pressure you should always take precautions. The pressure source should always be close when not in use. It is important to decrease the pressure in a coreholder before extracting the core.

7.3.3 Things that can be improved

During this process of writing my master thesis and working in the lab I have concluded that several thing leave room for improvement.

First I would like to look at the efficiency of the lab work that needed to be done. I had to do everything in the lab myself. It was very interesting and I learned a lot, but it was not optimal when thinking about efficiency. The experiments could have been executed faster if people in the lab had done some of the work. In the beginning I did not have proper routines for executing the different lab jobs, so it was not very efficient. After repeating the procedures a few times they were quickly done. The people helping me in the lab were in general very nice and helpful, but of course they had lot to do themselves so sometimes it was expected that I did things I knew nothing about. This was a bit time consuming since I had to learn the process myself.

Another thing I noticed while executing different experiment, was that if people borrowed some of your equipment they did not return it in the state they got it. I experienced in several incidents that the rig was not in the state I had left it. This was extremely irritating since some experiments got ruined due to my assumption that everything was in the state I left it. It is of course important to check that everything is as it should be before you start, but the common policy should be to leave things as they were.

An important area of improvement is the communication between lab workers and project leaders. Basically it needs to get better. The people working in the lab do not know as much about the procedures as would be preferable. They know the routine but they don’t know the consequence of what they are doing to the core. I also realized that the operators don’t know how much lab workers have to do. A project manager told me that the people in the lab could do some of mine experiments to make it go faster, but this was not reality. The lab workers had too much to do, and they were not notified by the project leader to prioritize my thesis. The lab workers are used to performing each test a certain way, which they think is the best way, but sometimes an understanding of the fluids movement in a core is needed. When I realized this I always asked project managers before doing something new.

In general more time would be preferred, because then more cores and more experiments could be run. 3 months is not a long time when working in the lab, it would be more than enough if everything went according to plan. Unexpected things always occurs, and the initially ambition had to be modified, to get some good results. It was originally planned to use 10 cores, and make them run 6 times in the rig plus one spontaneous imbibition experiment. Instead 6 cores were chosen and only 3-4 experiments in the rig and on spontaneous imbibition experiment were executed for every core.

Every experiment is time consuming, and the preparation of the cores before installing them in the USS rig is very time consuming. So if something goes wrong, it will take at least 3 days before the test can run again on the same core. It’s not much to do about this, there is not possible to predict everything that might go wrong. I have experienced that Murphys law applies when doing lab work.

8 Conclusion

1. Water should be used as the wetting phase, if it is desirable to find S_{gr} when $\Delta P < 0$ and $\Delta P = 0$. Capillary forces will not be strong enough for this purpose when using IsoparL as wetting phase.
2. When using IsoparL as the wetting phase, all USS experiments will take place in the region of $\Delta P > 0$.
3. If IsoparL is the wetting phase, the general trend will be that S_{gr} decreases when rate increases.
4. By studying cores with same initial saturation at the same rate it was clear that S_{gr} increases as porosity increases.
5. By studying cores with approximately the same initial saturation at the same rate no clear trend was found between S_{gr} and permeability
6. By studying cores with similar porosity and permeability at the same rate, a trend between initial IsoparL saturation and S_{gr} was discovered. S_{gr} will decrease as S_{oi} increases.

Definitions

Residual gas saturation: Amount of gas that can not move

Microporosity: the part of the pores were the dimensions are less than 1 micron (Schlumberger 2012)

Consolidated: when sediments have been compacted and cemented to the extent theta they have become coherent. Consequents of consolidating are increased density and decreased porosity.

Ambient conditions: Conditions at atmospheric pressure and temperature

Murphys law: If anything can go wrong, it will

Nomenclatur

A = cross-sectional area

G_t = trapped gas

r = radius

S_o: oil saturation

S_{oi} : initial oil saturation

S_{gi} : initial gas saturation

S_g: gas saturation

S_{gr}: residual gas saturation

S_{grM} : maximum residual gas saturation

V_p and PV: pore volume

V_b : bulk volume

V_m : matrix volume

Q : rate

ρ_{air} : air density

$\rho_{IsoparL}$: IsoparL density

ΔP : pressure difference

P_c : capillary pressure

k : permeability

φ : porosity

µ : viscosity

σ : surface tension

IFT : Interfacial tension

PV : pore volume

RF : recovery factor

RPM: rounds per minute

USS : unsteady state

WI : Amott-Harvey relative wettability index

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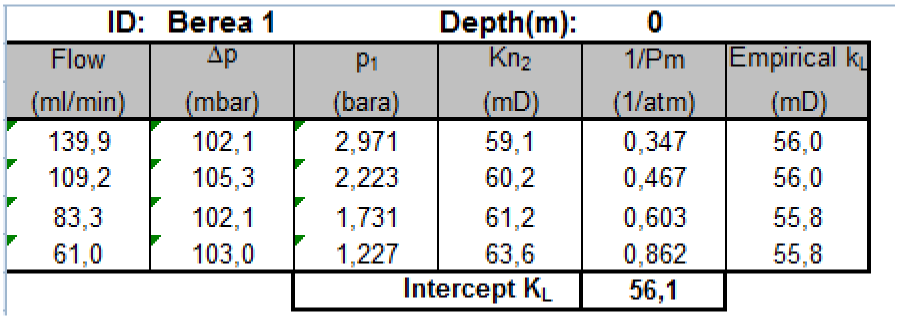
Appendix

Appendix A - permeability

Table A- 1 - Permeability data for Berea 1



ID:	Berea 1		Depth(m):	0	
Flow (ml/min)	Δp (mbar)	p$_1$ (bara)	Kn$_2$ (mD)	1/Pm (1/atm)	Empirical k$_L$ (mD)
139,9	102,1	2,971	59,1	0,347	56,0
109,2	105,3	2,223	60,2	0,467	56,0
83,3	102,1	1,731	61,2	0,603	55,8
61,0	103,0	1,227	63,6	0,862	55,8
		Intercept K$_L$		56,1	

1

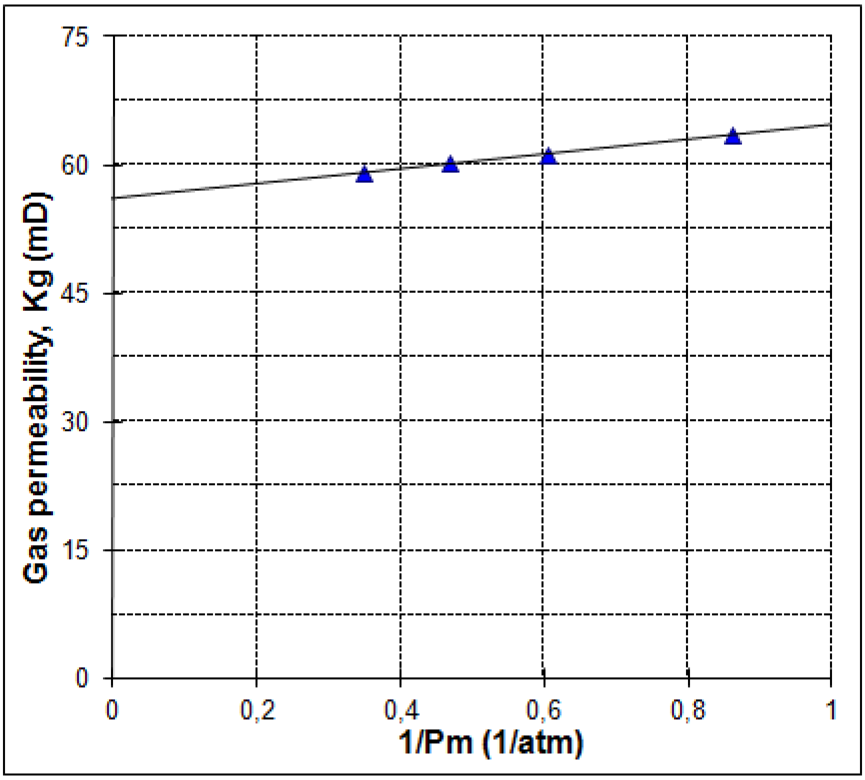
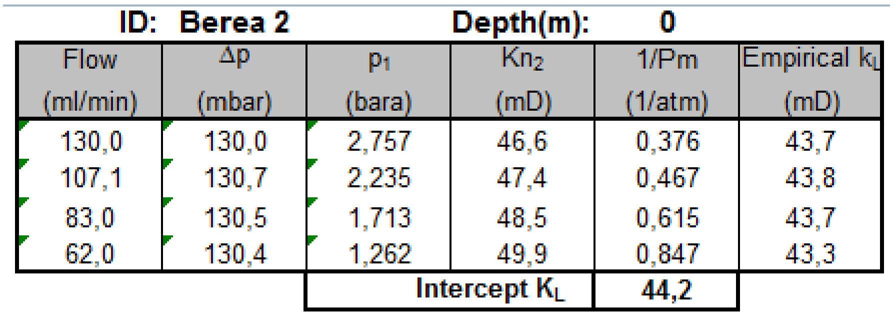


Fig. A- 1 - Graph for finding absolute permeability for Berea 1

Table A- 2 - Permeability data for Berea 2



ID: Berea 2 **Depth(m): 0**

Flow (ml/min)	Δp (mbar)	p_1 (bara)	Kn_2 (mD)	1/Pm (1/atm)	Empirical k_L (mD)
130,0	130,0	2,757	46,6	0,376	43,7
107,1	130,7	2,235	47,4	0,467	43,8
83,0	130,5	1,713	48,5	0,615	43,7
62,0	130,4	1,262	49,9	0,847	43,3
		Intercept K_L		44,2	

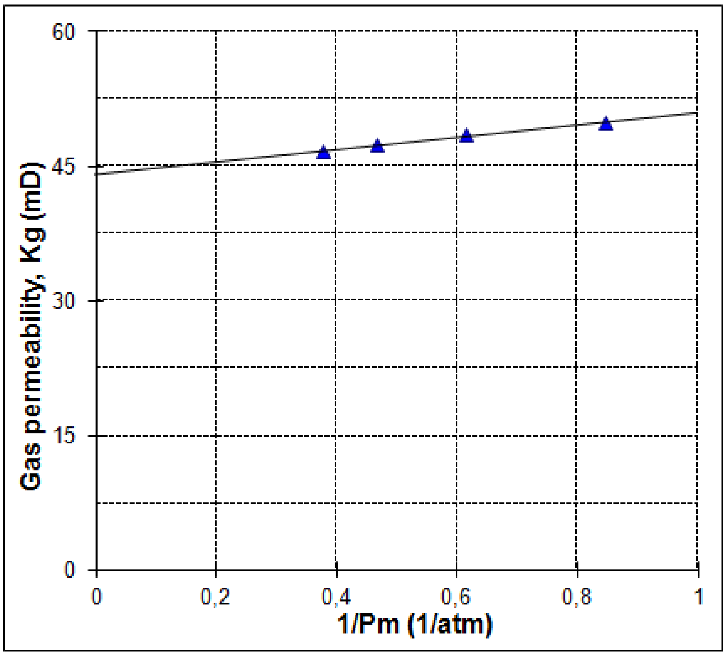
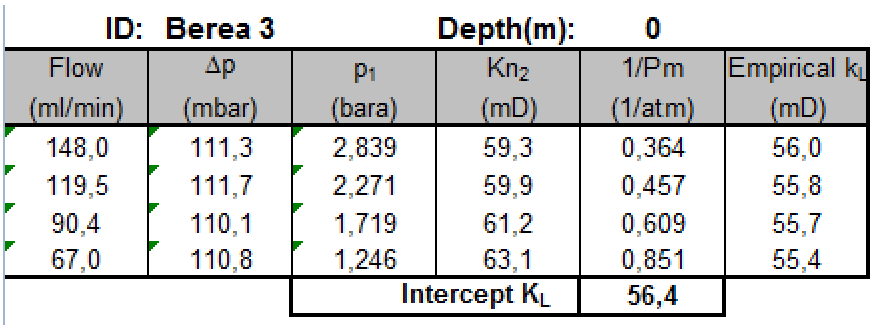


Fig. A- 2 - Graph for finding absolute permeability for Berea 2

Table A- 3 - Permeability data for Berea 3



ID: Berea 3 **Depth(m): 0**

Flow (ml/min)	Δp (mbar)	p_1 (bara)	Kn_2 (mD)	1/Pm (1/atm)	Empirical k_L (mD)
148,0	111,3	2,839	59,3	0,364	56,0
119,5	111,7	2,271	59,9	0,457	55,8
90,4	110,1	1,719	61,2	0,609	55,7
67,0	110,8	1,246	63,1	0,851	55,4
		Intercept K_L		56,4	

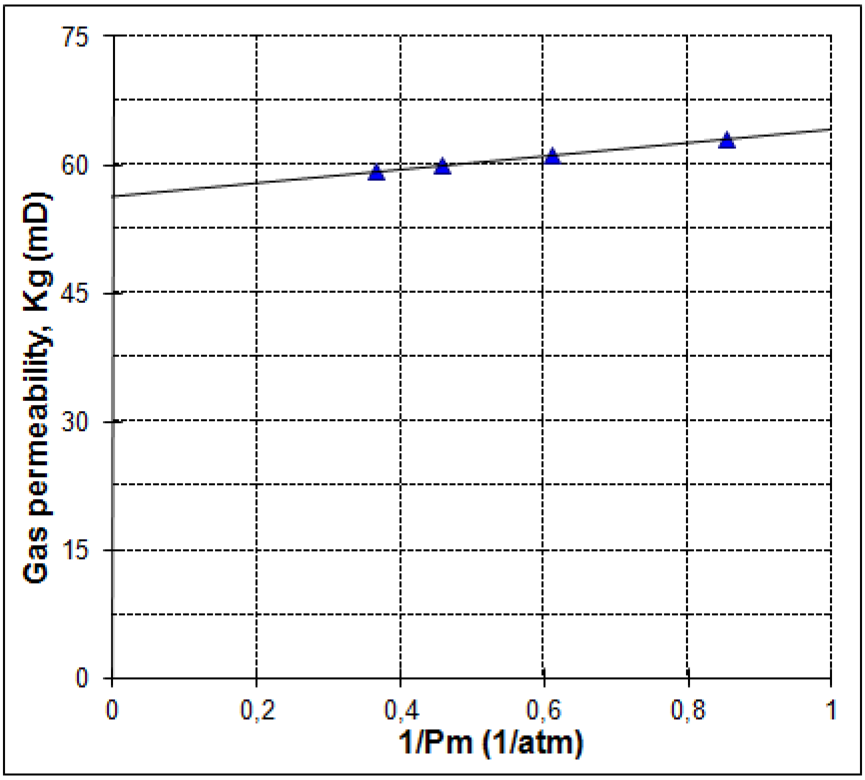
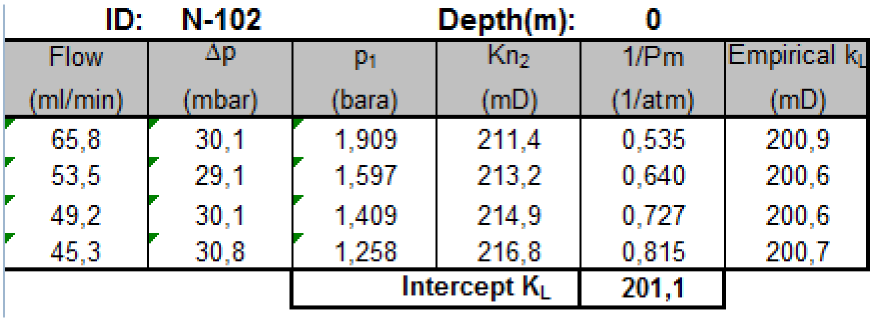


Fig. A- 3 - Graph for finding absolute permeability for Berea 3

Table A- 4 - Permeability data for N-102



ID: **N-102** **Depth(m):** **0**

Flow (ml/min)	Δp (mbar)	p_1 (bara)	Kn_2 (mD)	1/Pm (1/atm)	Empirical k_L (mD)
65,8	30,1	1,909	211,4	0,535	200,9
53,5	29,1	1,597	213,2	0,640	200,6
49,2	30,1	1,409	214,9	0,727	200,6
45,3	30,8	1,258	216,8	0,815	200,7
			Intercept K_L	**201,1**	

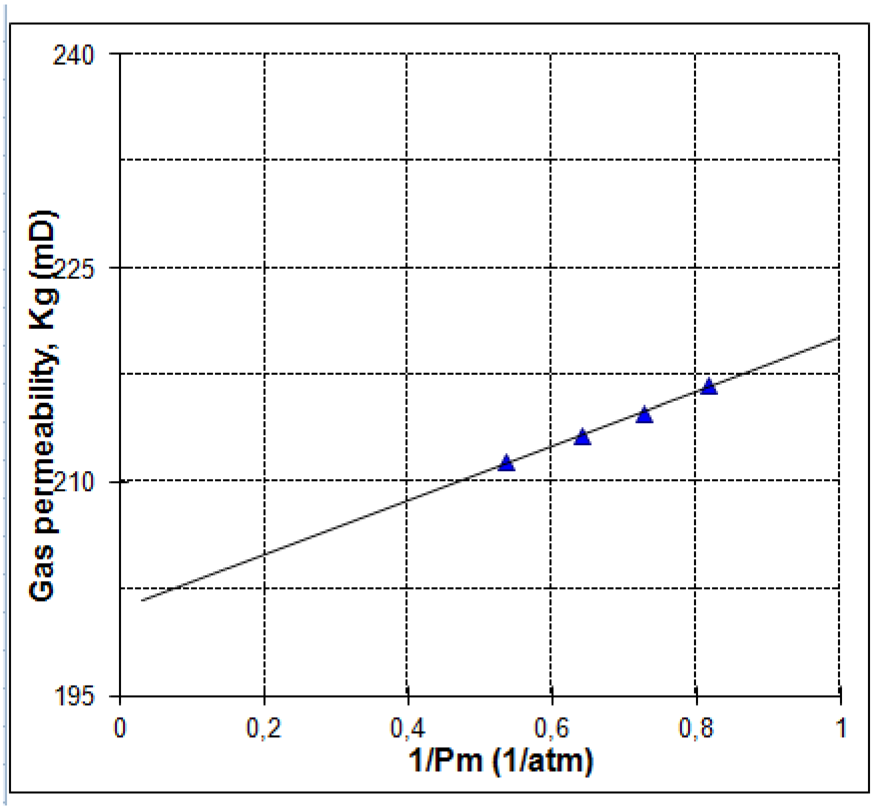
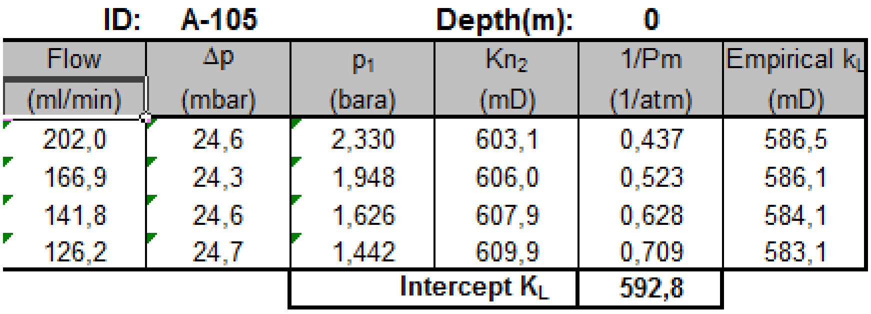


Fig. A- 4 - Graph for finding absolute permeability for N-102

Table A- 5 - Permeability data for N-105



ID: **A-105** **Depth(m):** **0**

Flow (ml/min)	Δp (mbar)	p_1 (bara)	Kn_2 (mD)	1/Pm (1/atm)	Empirical k_L (mD)
202,0	24,6	2,330	603,1	0,437	586,5
166,9	24,3	1,948	606,0	0,523	586,1
141,8	24,6	1,626	607,9	0,628	584,1
126,2	24,7	1,442	609,9	0,709	583,1
		Intercept K_L		**592,8**	

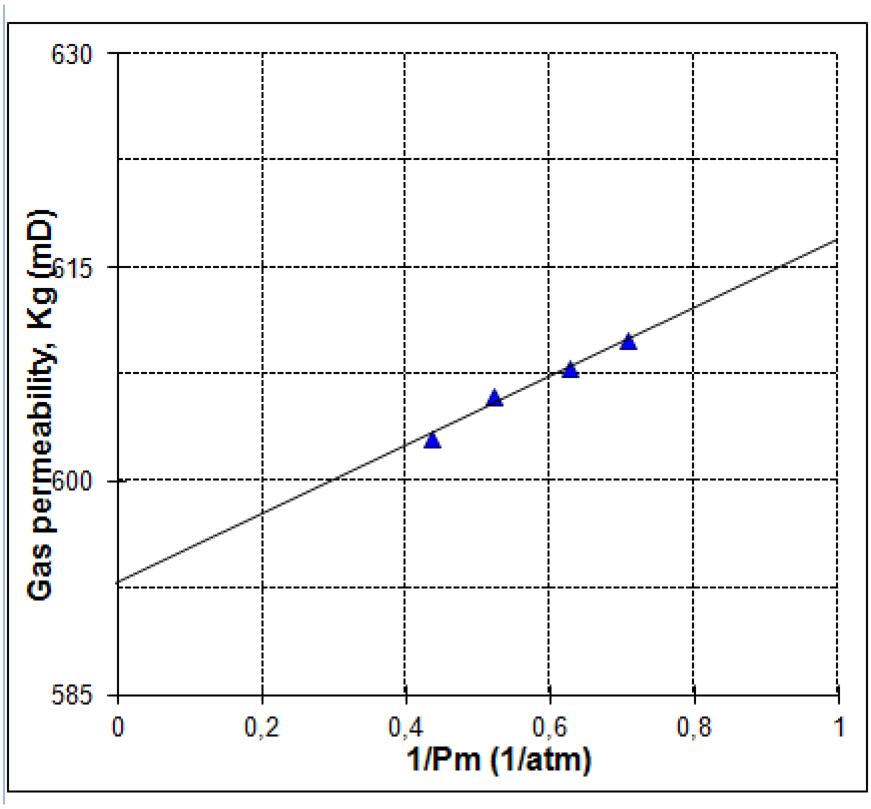
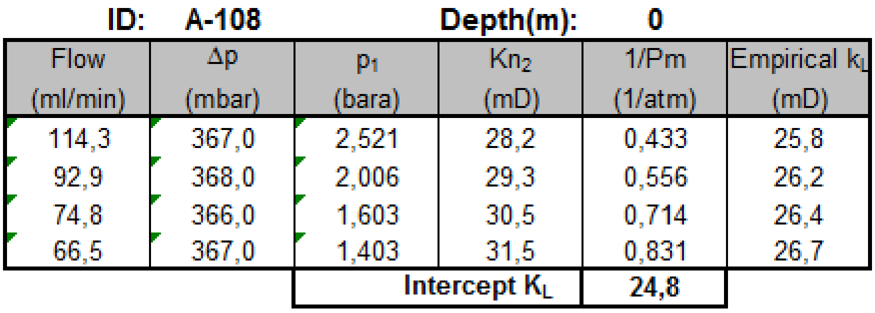


Fig. A- 5 - Graph for finding absolute permeability for N-105

Table A- 6 - Permeability data for N-108



ID: A-108 **Depth(m): 0**

Flow (ml/min)	Δp (mbar)	p_1 (bara)	Kn_2 (mD)	1/Pm (1/atm)	Empirical k_L (mD)
114,3	367,0	2,521	28,2	0,433	25,8
92,9	368,0	2,006	29,3	0,556	26,2
74,8	366,0	1,603	30,5	0,714	26,4
66,5	367,0	1,403	31,5	0,831	26,7
		Intercept K_L		24,8	

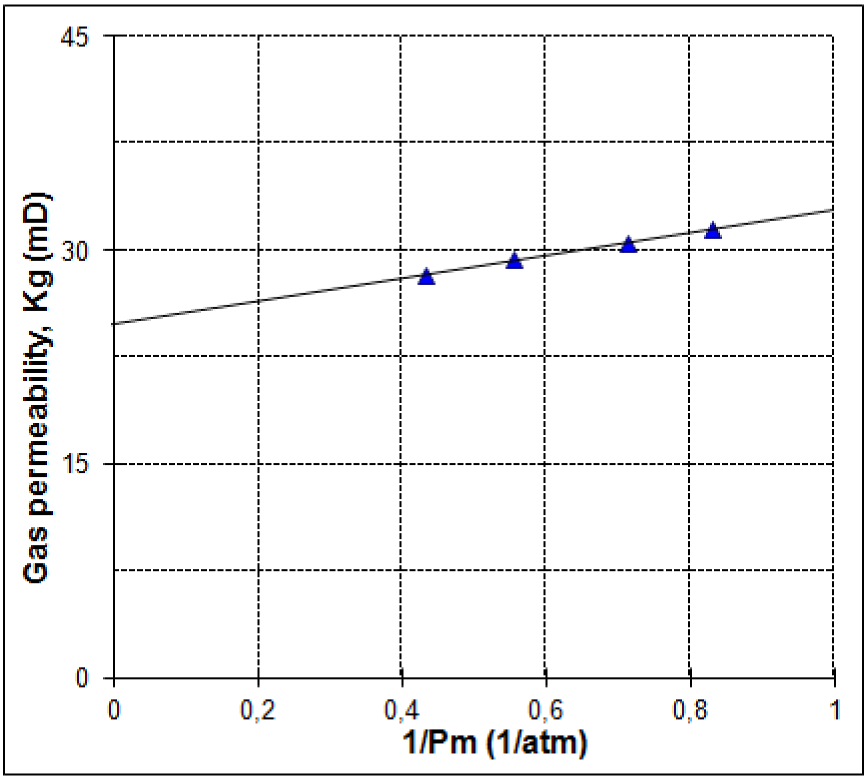


Fig. A- 6 - Graph for finding absolute permeability for N-108

Appendix B – Spontaneous imbibition experiment

B.1 Finding average rate

For finding the average rate of the spontaneous imbibition experiment, the slope of the injected IsoparL graph was calculated. In this appendix these graphs and the calculated Q are presented.

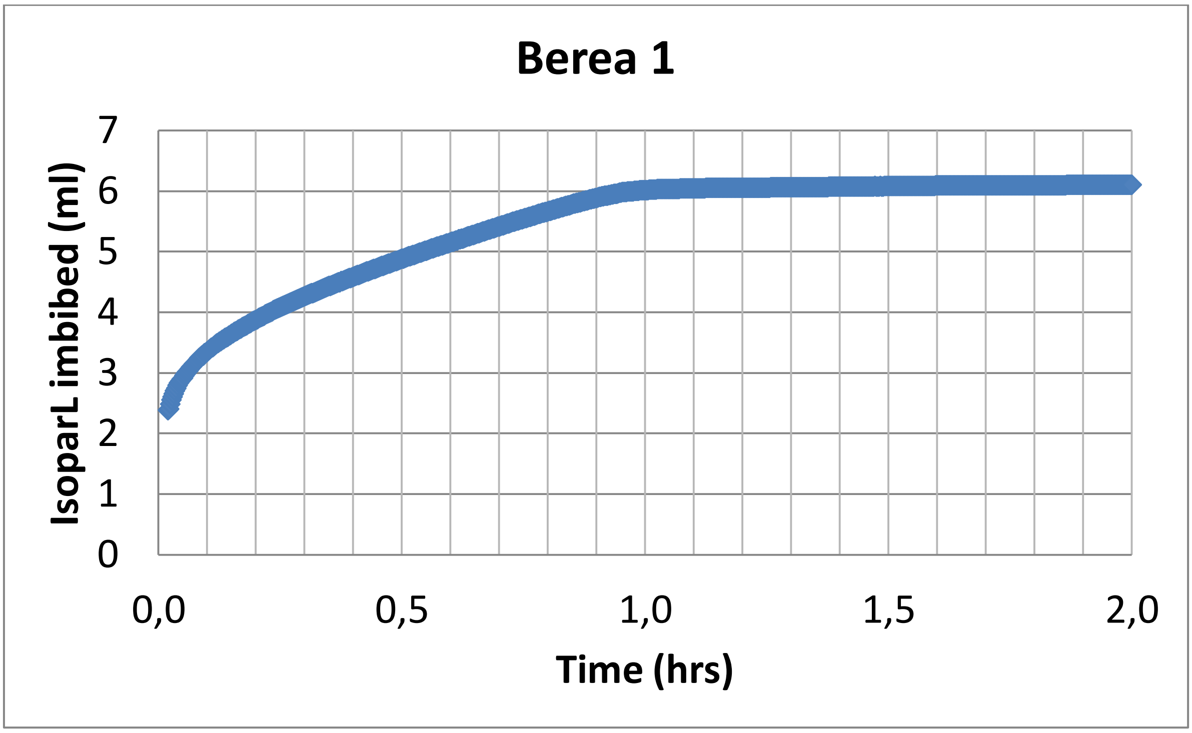


Fig. B - 1– Graph for finding average rate, Berea 1

$$Q_{Berea1} = \frac{5.64 - 4.01}{0.786 - 0.231} = 2.93 ml / h \quad \text{(B -1)}$$

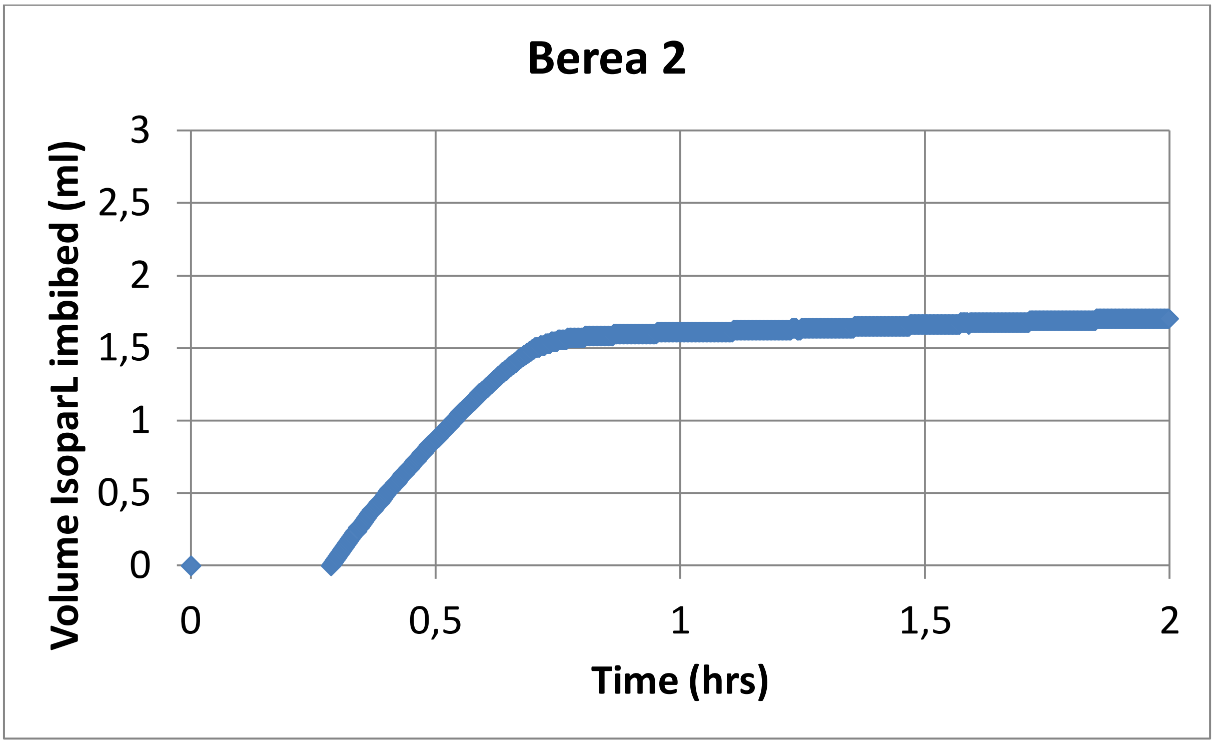


Fig. B - 2 - Graph for finding average rate, Berea 2

$$Q_{Berea2} = \frac{1.22 - 0.21}{0.603 - 0.33} = 3.7 ml / h \qquad \text{(B -2)}$$

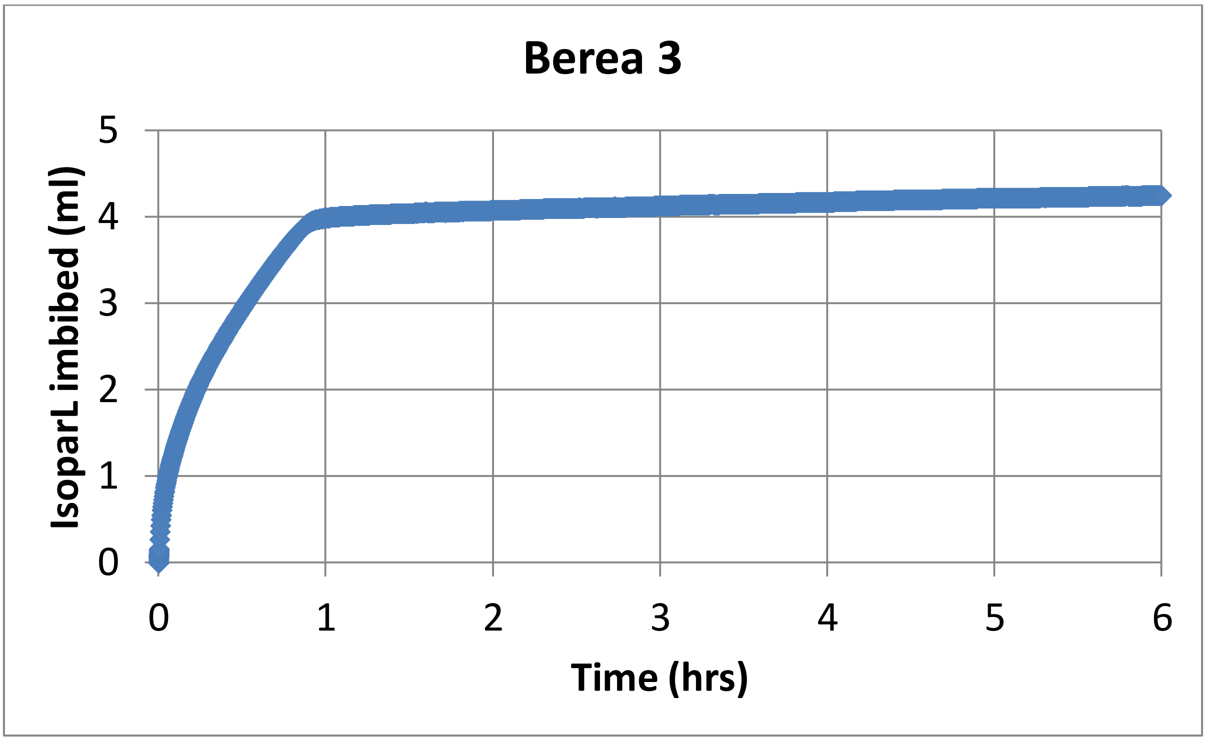


Fig. B - 3 - Graph for finding average rate, Berea 3

$$Q_{Berea3} = \frac{3.36 - 2.01}{0.65 - 0.229} = 3.2 ml / h \qquad \text{(B -3)}$$

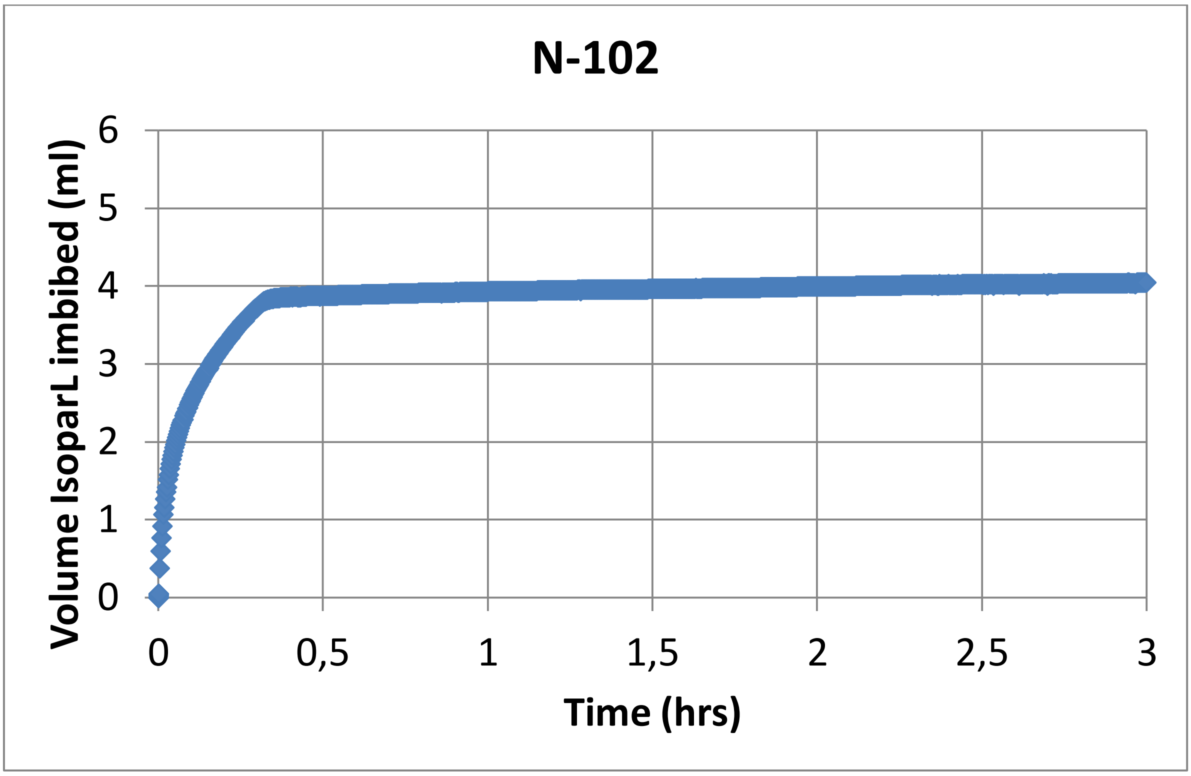


Fig. B - 4- Graph for finding average rate, N-102

$$Q_{N-102} = \frac{3.04 - 2.18}{0.164 - 0.064} = 8.6 ml / h \tag{B -4}$$

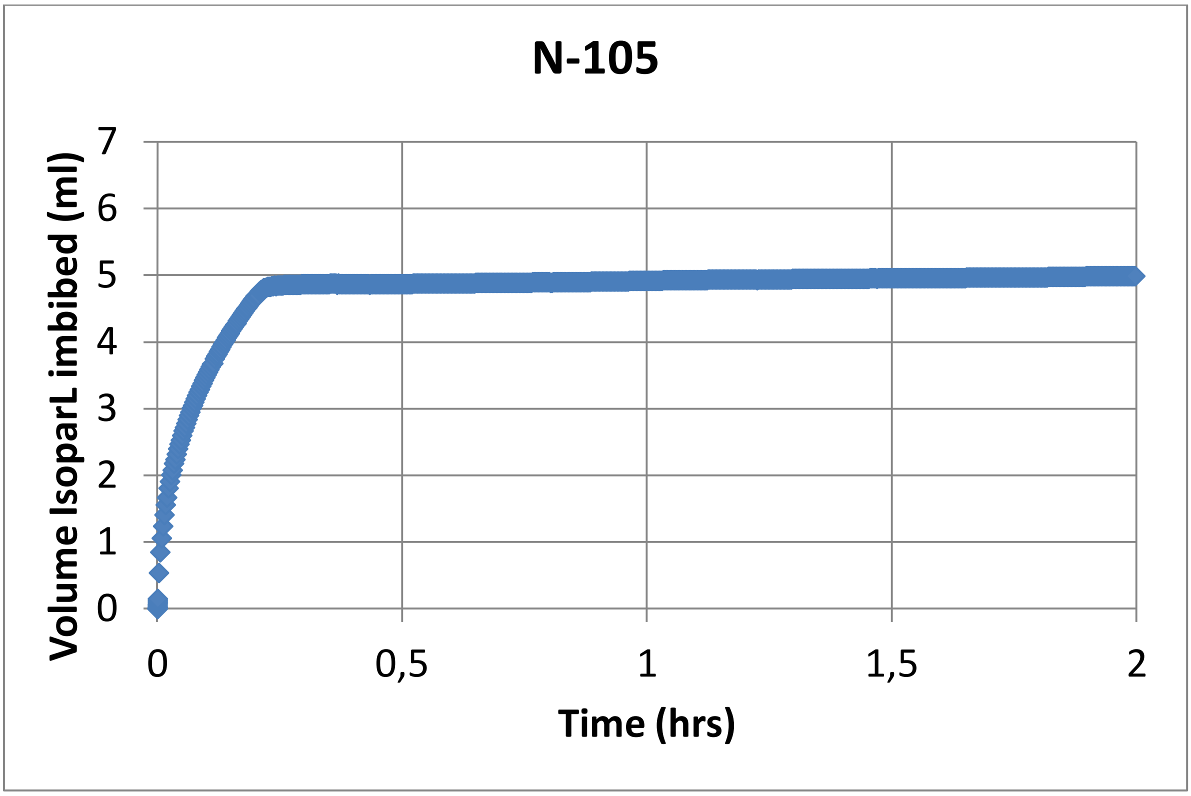


Fig. B - 5- Graph for finding average rate, N-105

$$Q_{N-105} = \frac{4.07 - 2.4}{0.14 - 0.04} = 16.7 ml / h \qquad \text{(B -5)}$$

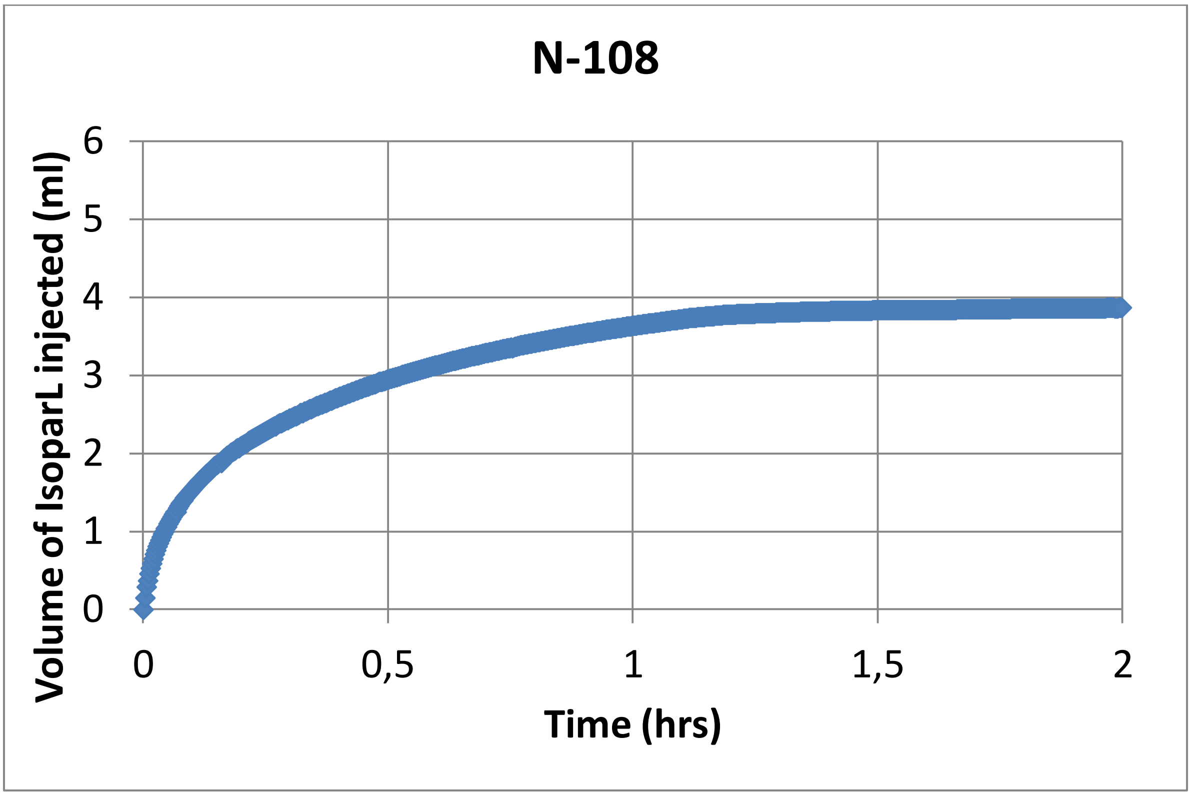


Fig. B - 6 - Graph for finding average rate, N-108

$$Q_{N-108} = \frac{3.55 - 2.07}{0.909 - 0.196} = 2.08 ml / h \qquad \text{(B -6)}$$

Appendix C – USS

C.1 Q = 4 ml/h

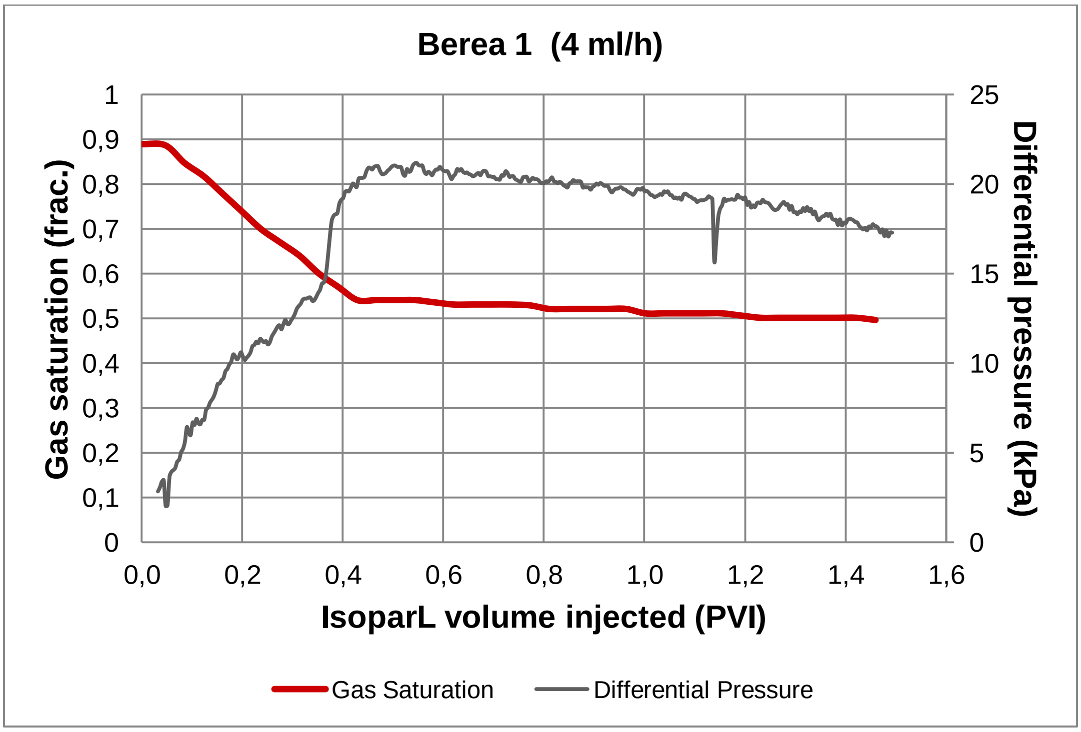


Fig. C - 1– Gas saturation at low rate injectiom, Berea 1

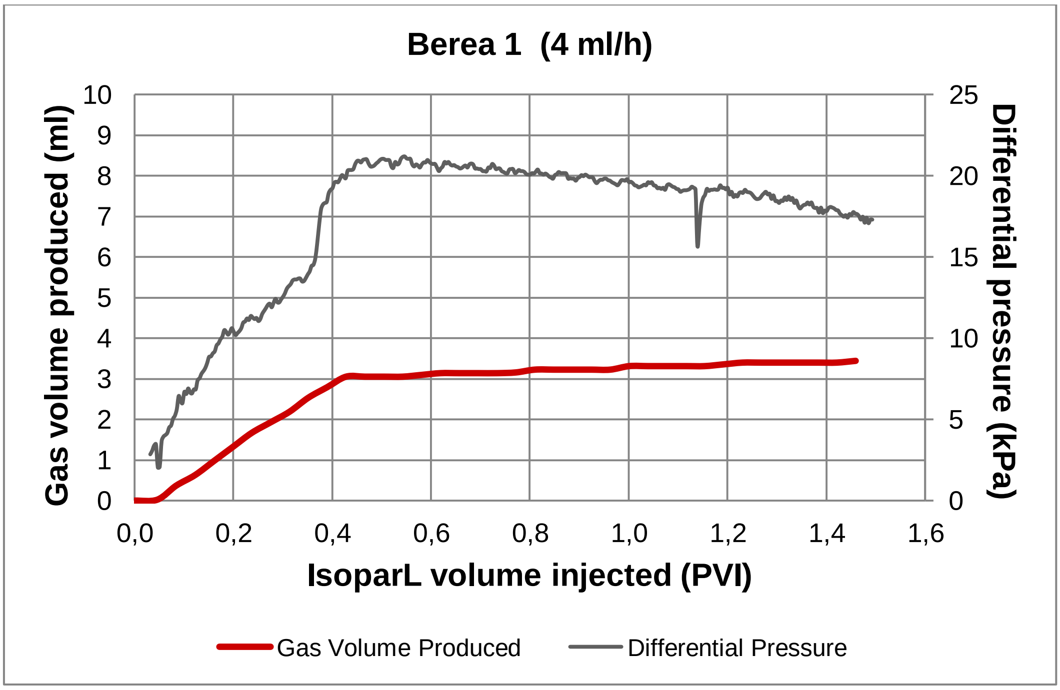


Fig. C - 2– Gas volume produced at low rate injection, Berea 1

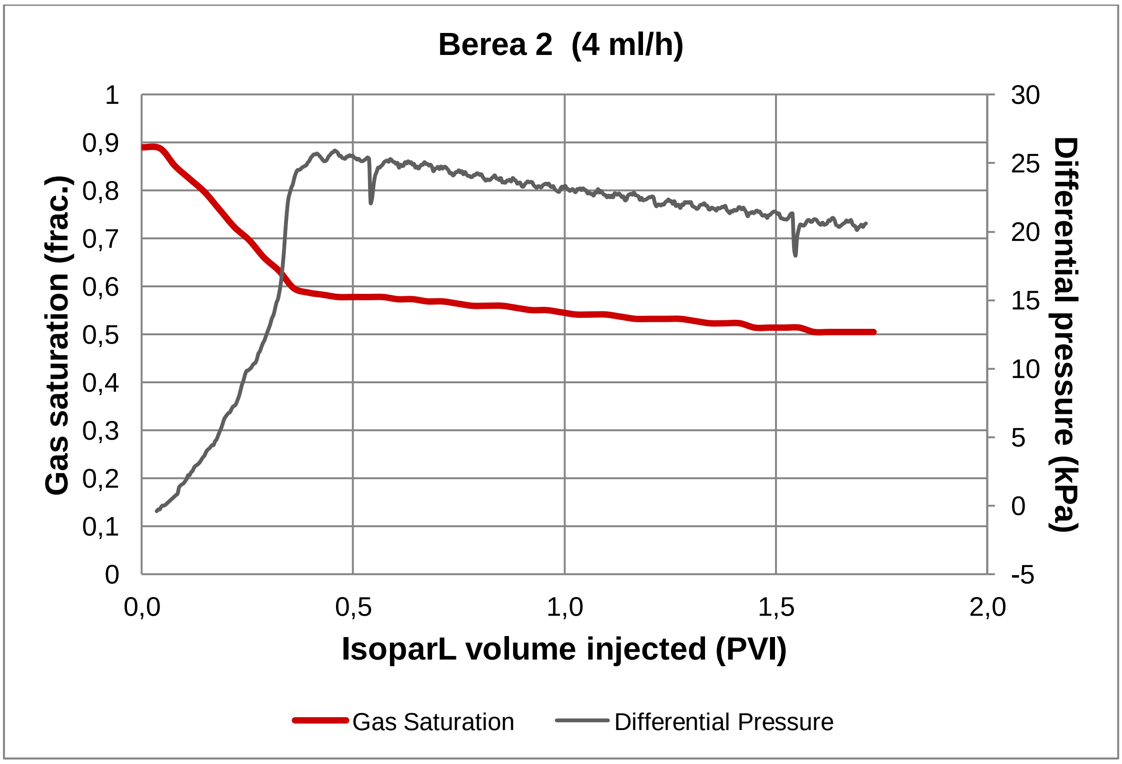


Fig. C - 3 - Gas saturation at low rate injectiom, Berea 2

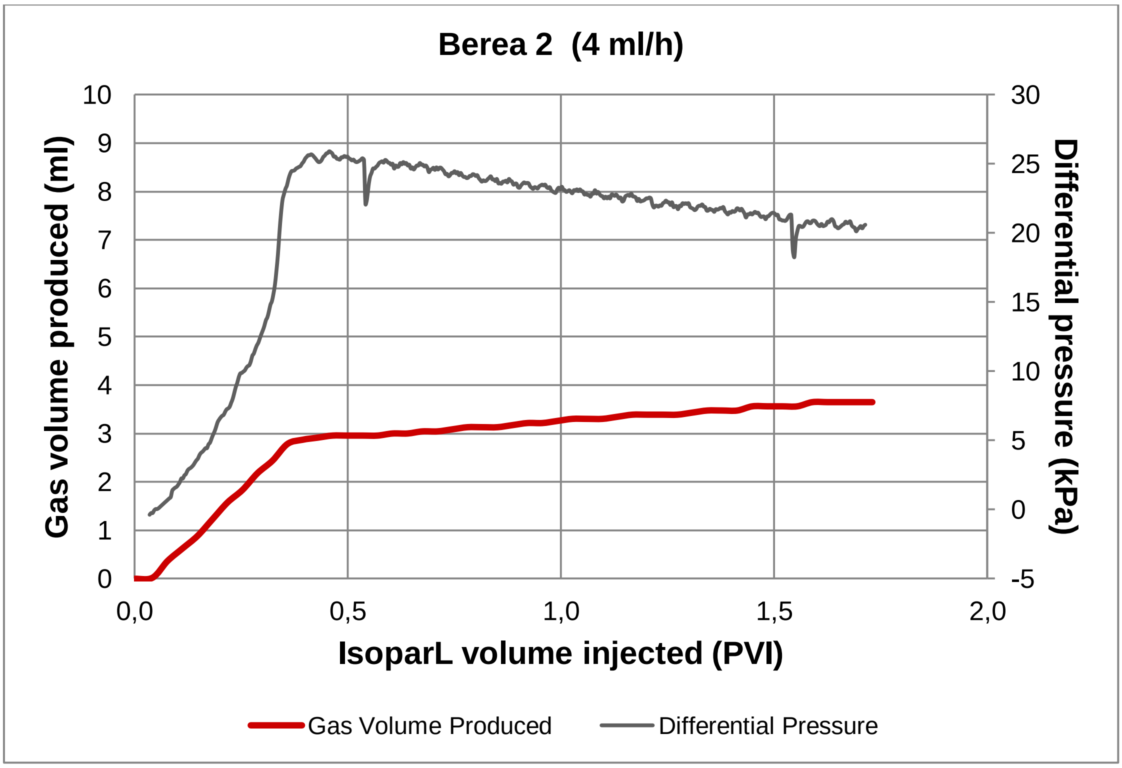


Fig. C - 4 - Gas volume produced at low rate injection, Berea 2

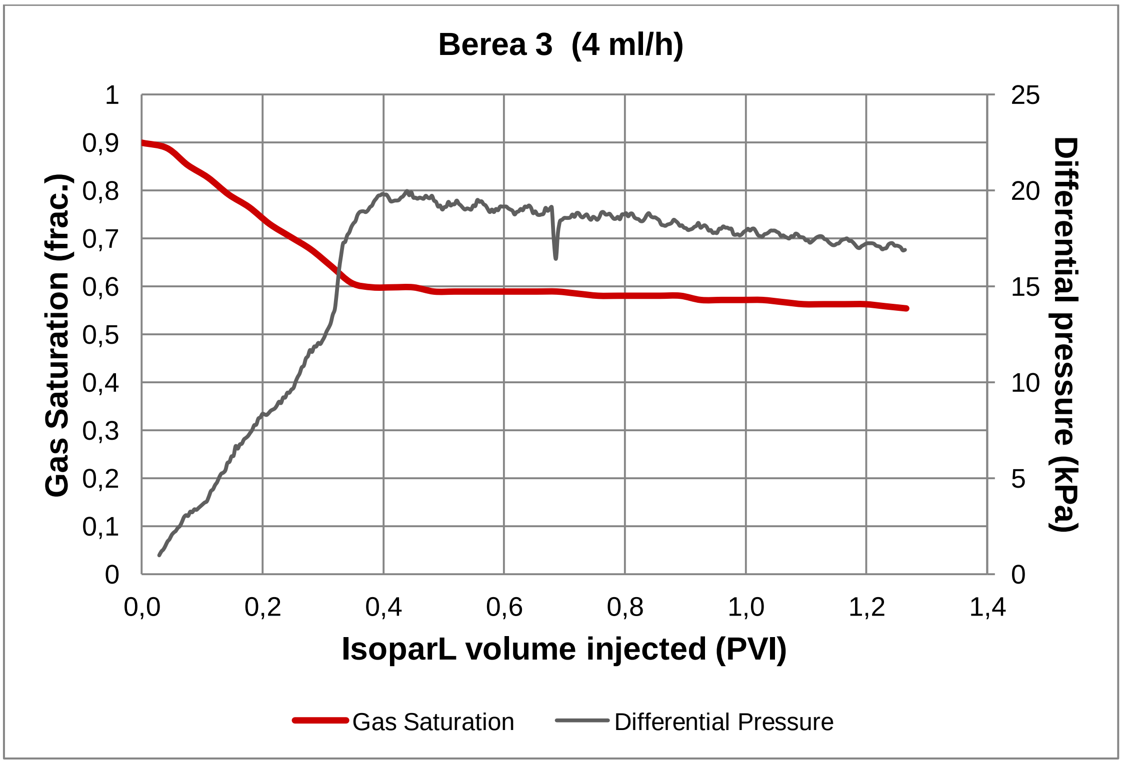


Fig. C - 5 – Gas saturation at low rate injectiom, Berea 3

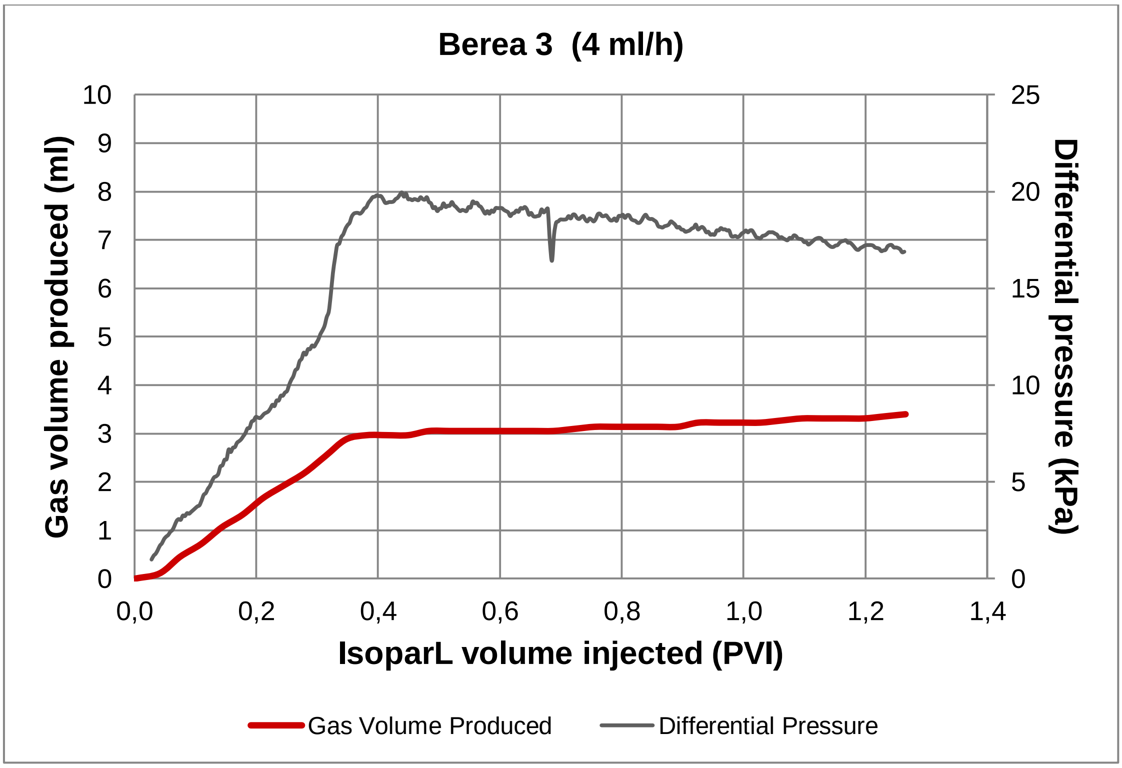


Fig. C - 6 - Gas volume produced at low rate injection, Berea 3

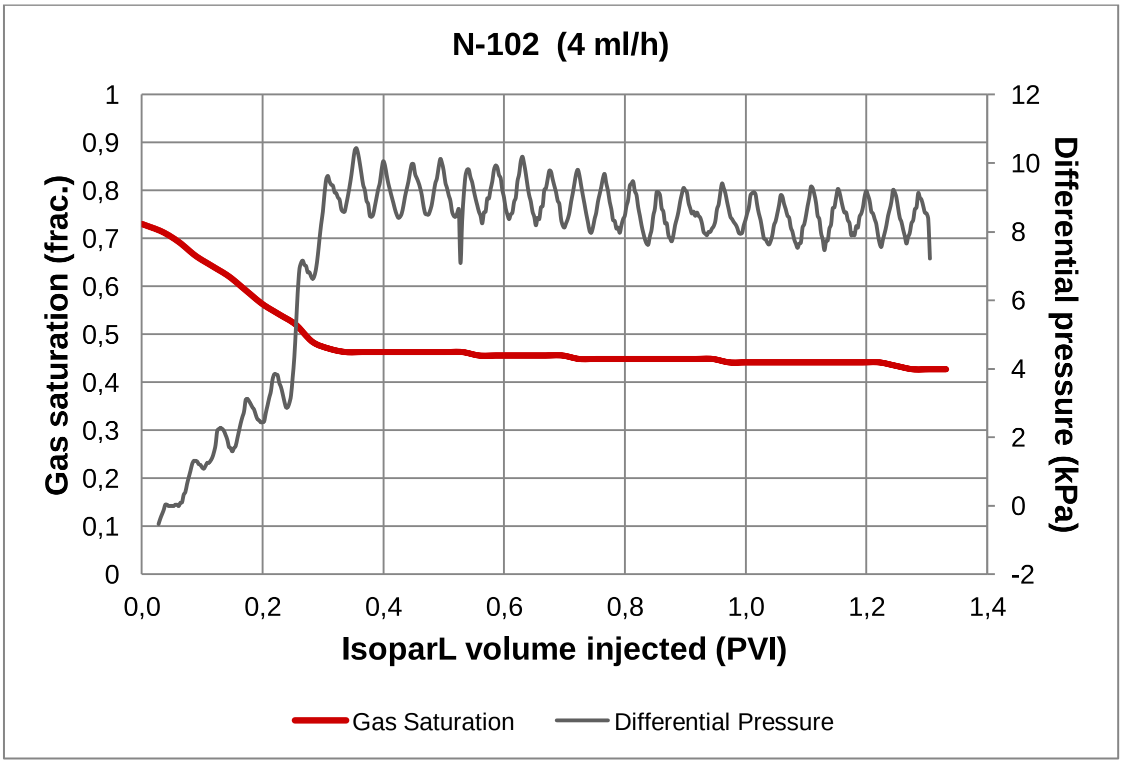


Fig. C - 7- Gas saturation at low rate injectiom, N-102

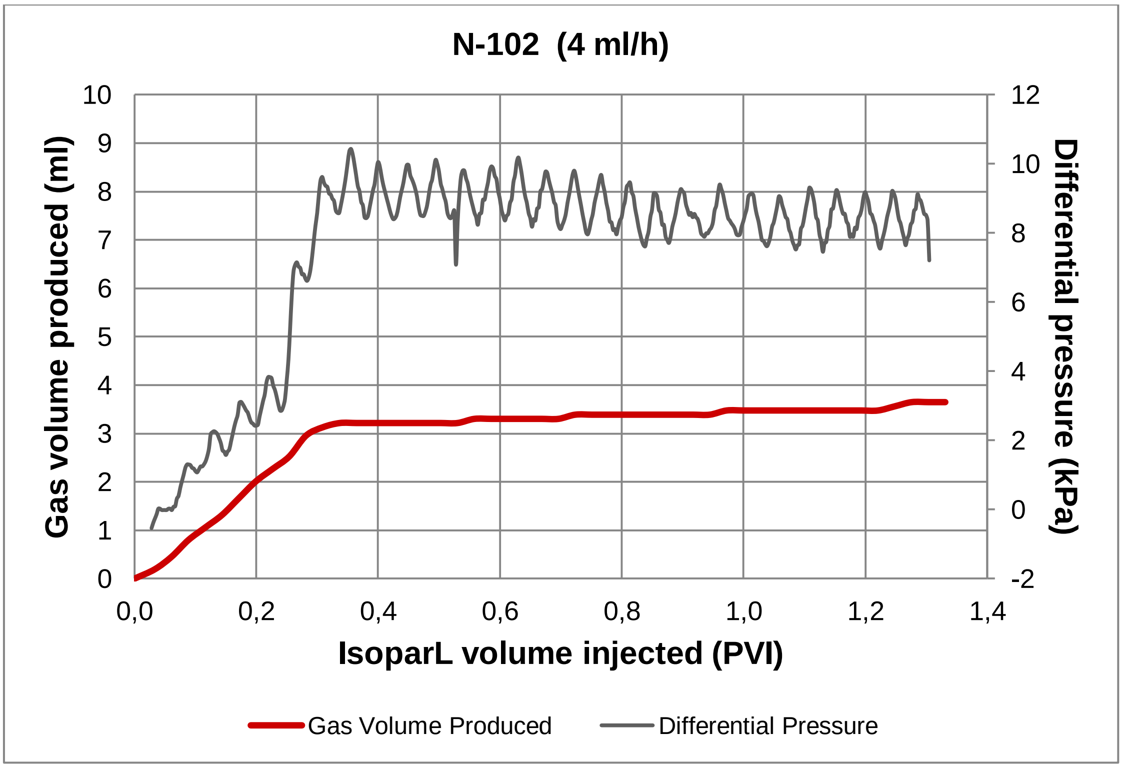


Fig. C - 8 - Gas volume produced at low rate injection, N-102

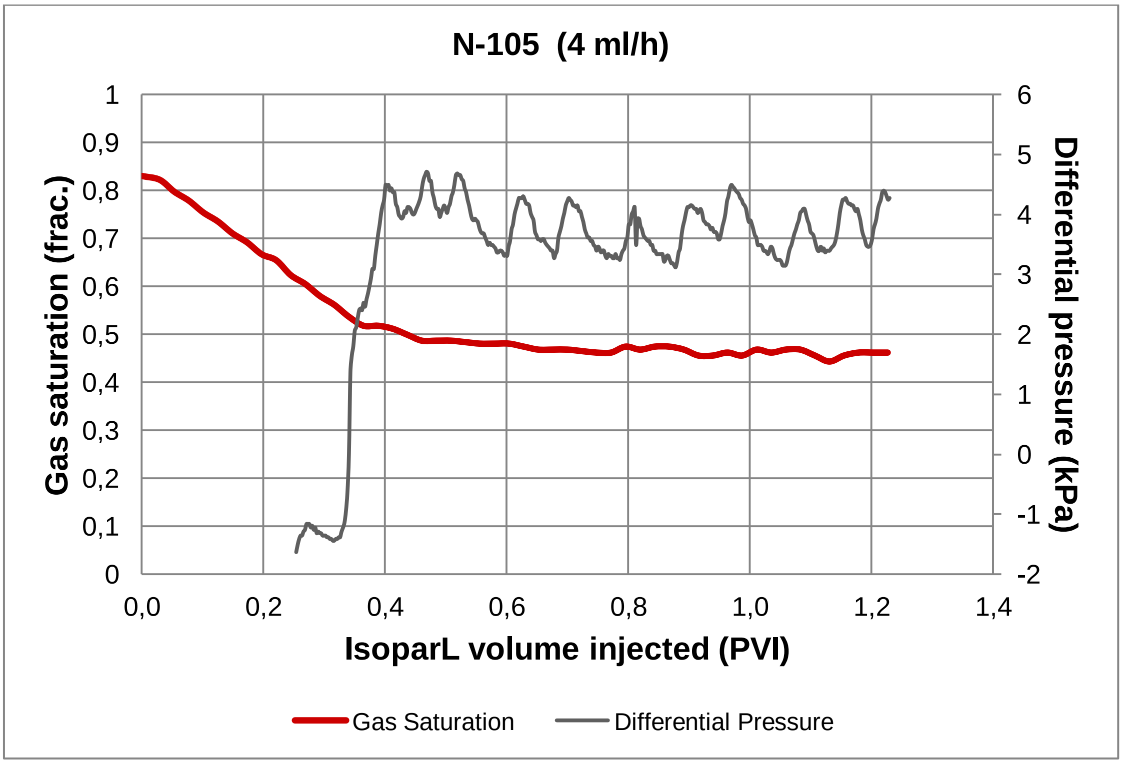


Fig. C - 9- Gas saturation at low rate injectiom, N-105

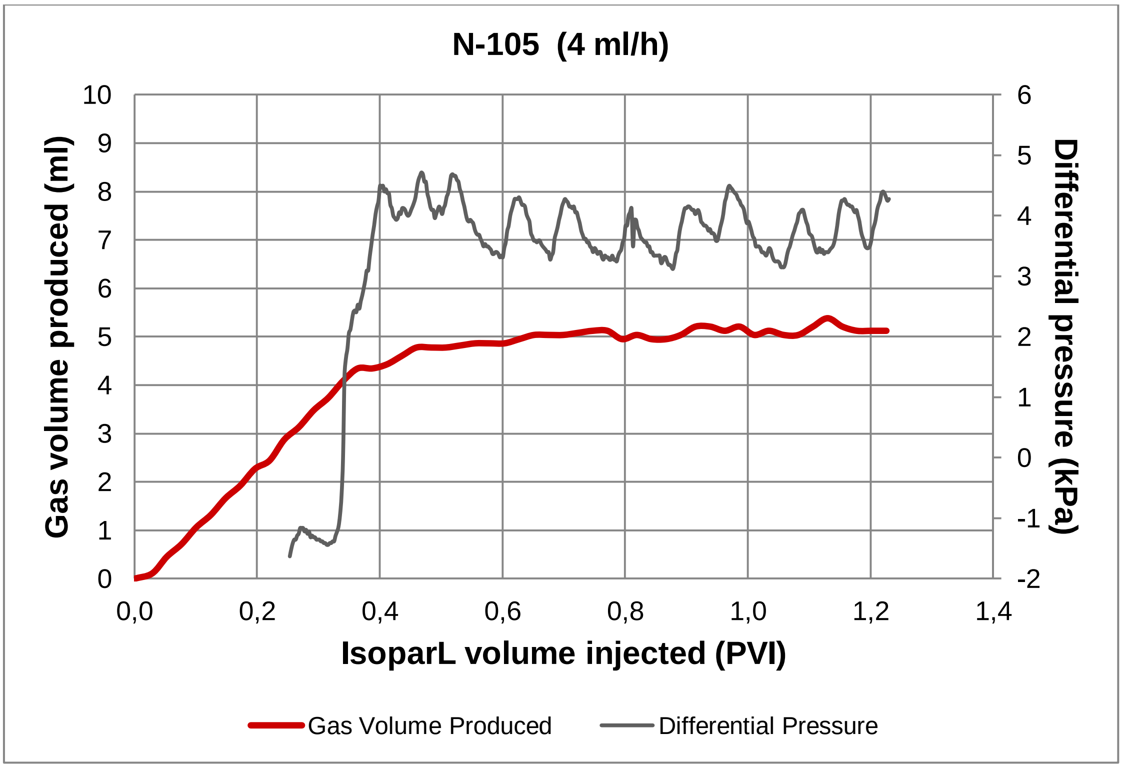


Fig. C - 10 - Gas volume produced at low rate injection, N-105

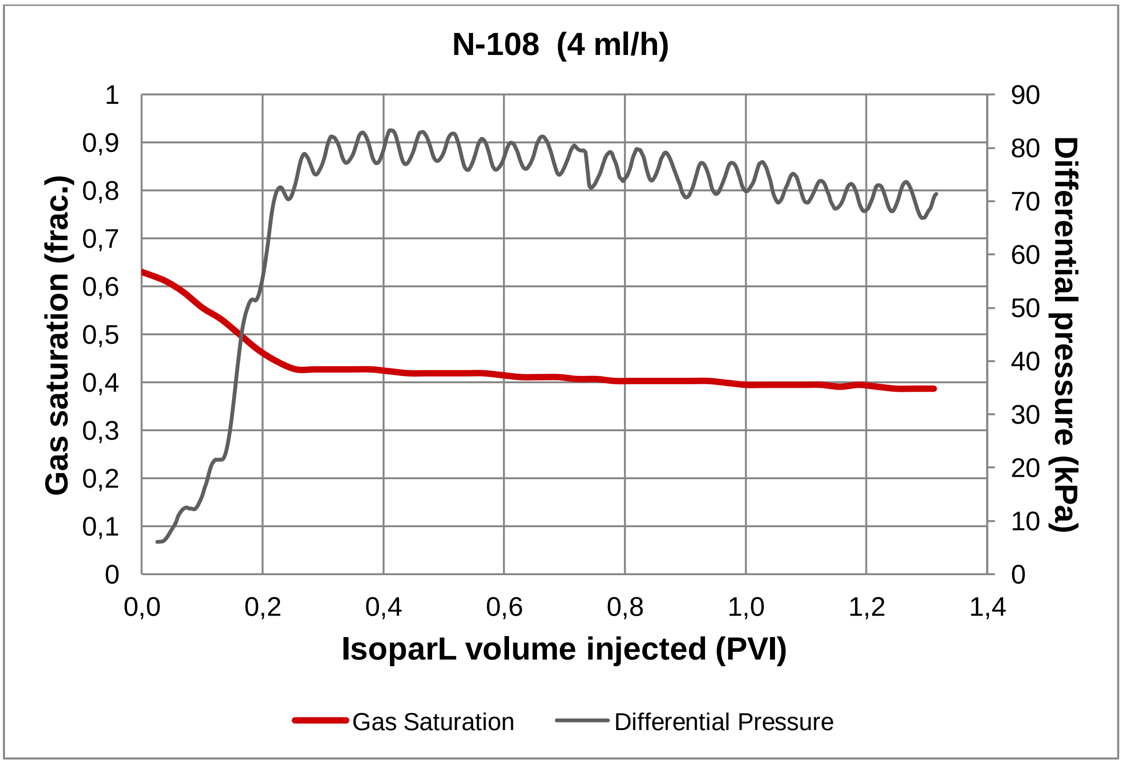


Fig. C - 11 - Gas saturation at low rate injectiom, N-108

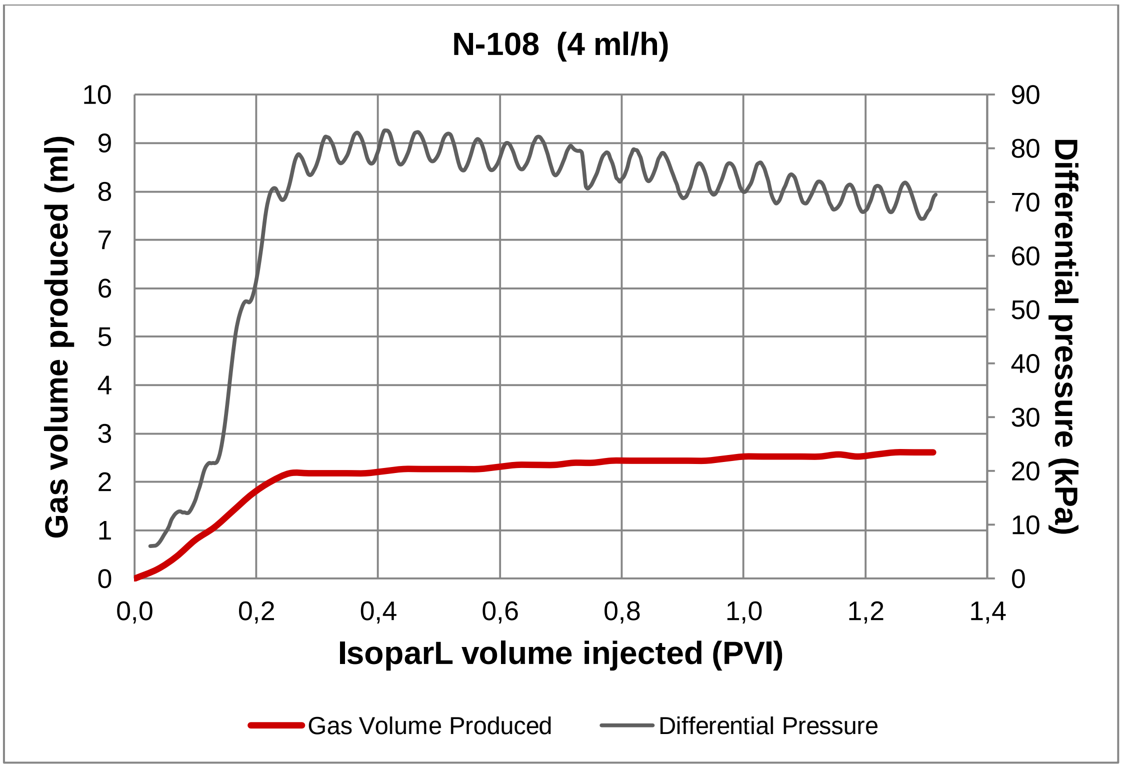


Fig. C - 12 - Gas volume produced at low rate injection, N-108

C.2 Q = 10-50 ml/h

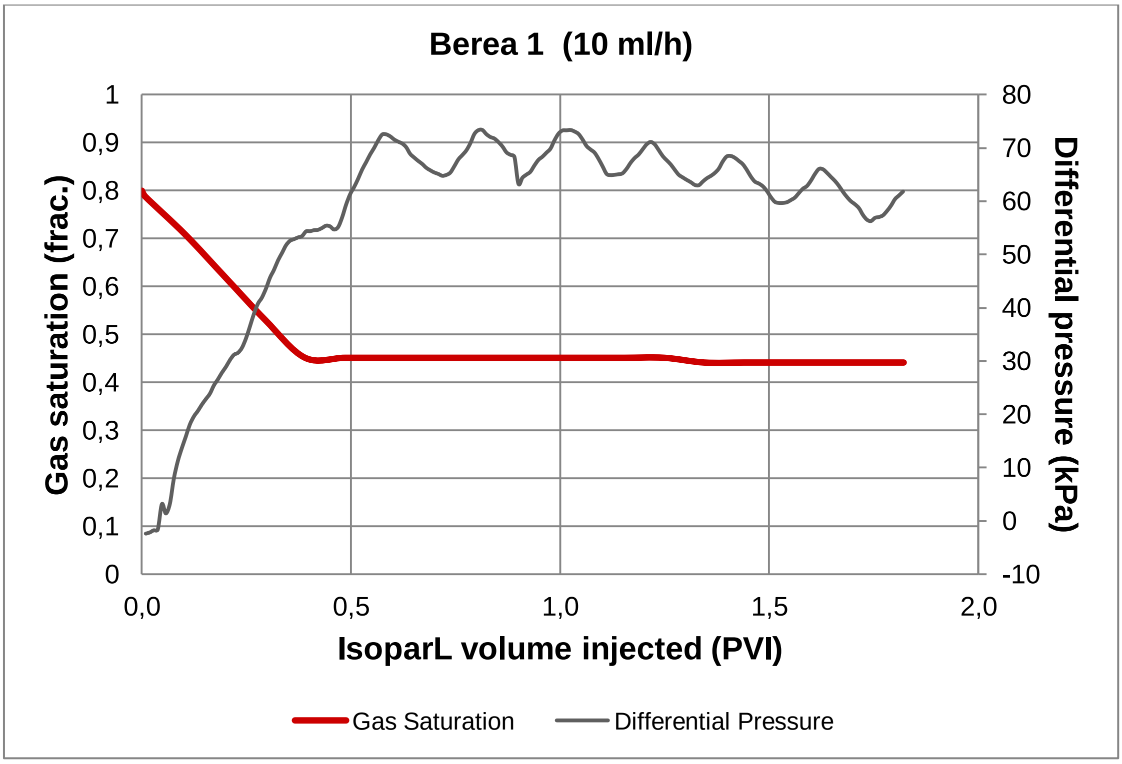


Fig. C - 13 – Gas saturation at low rate injectiom, Berea 1

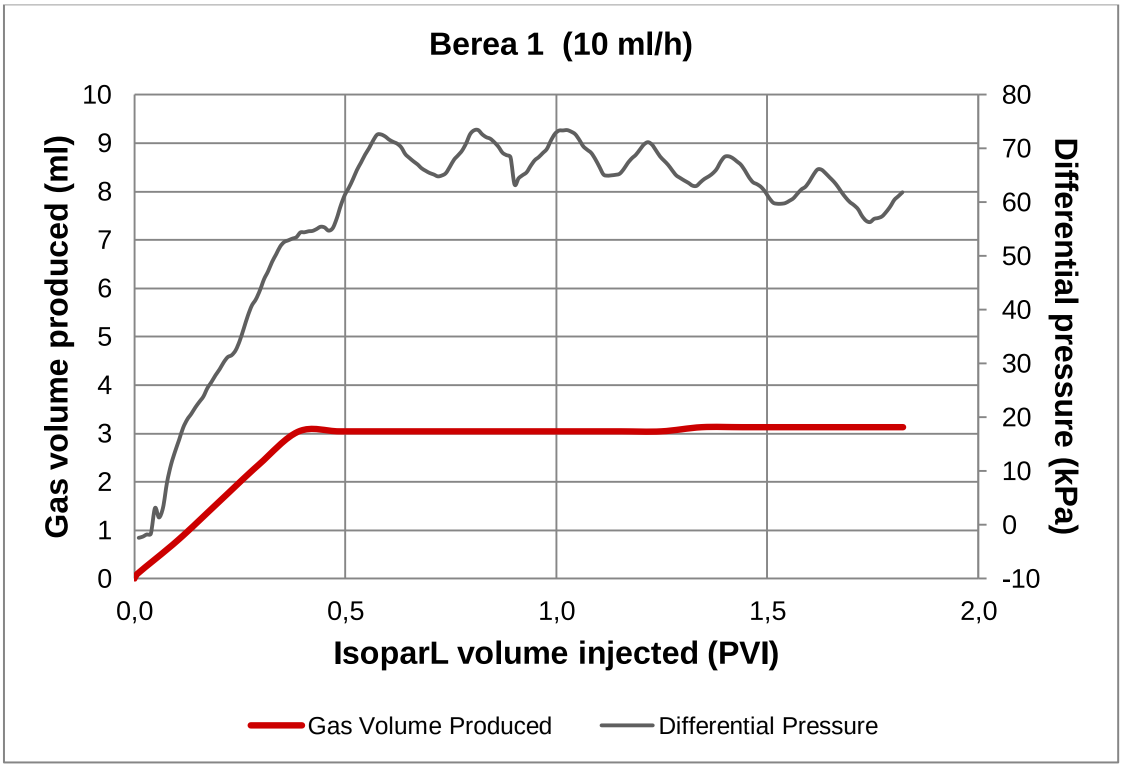


Fig. C - 14– Gas volume produced at low rate injection, Berea 1

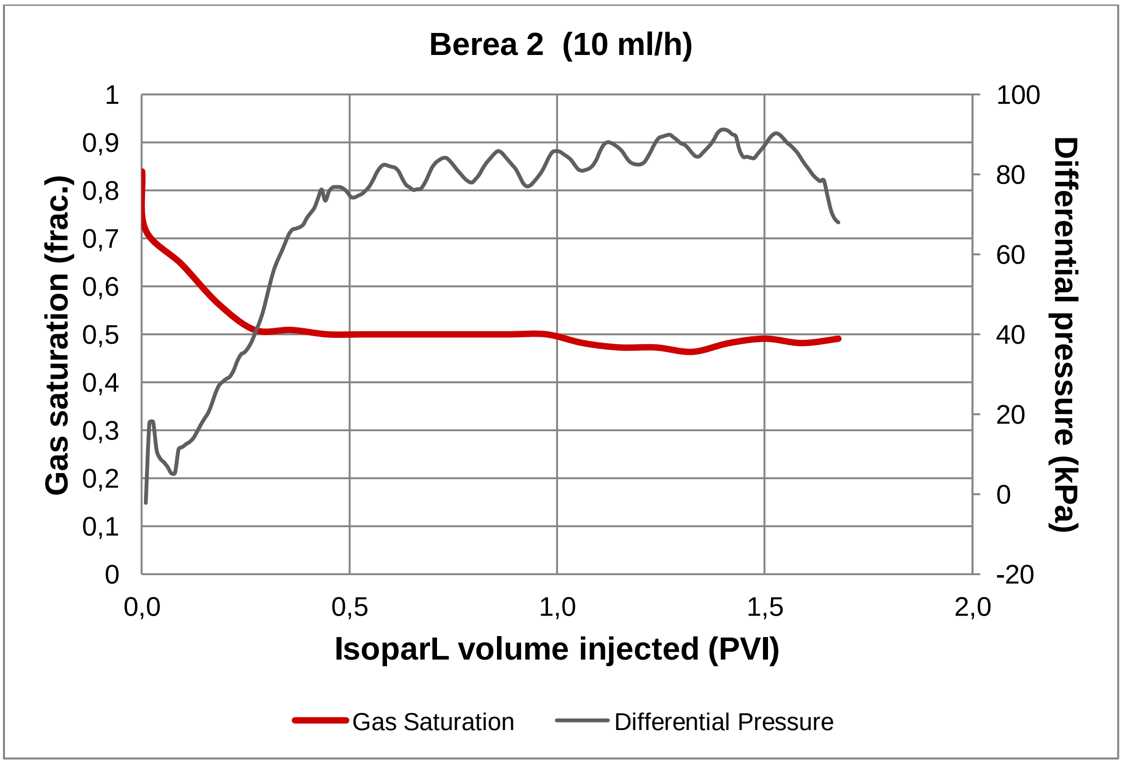


Fig. C - 15 – Gas saturation at low rate injectiom, Berea 2

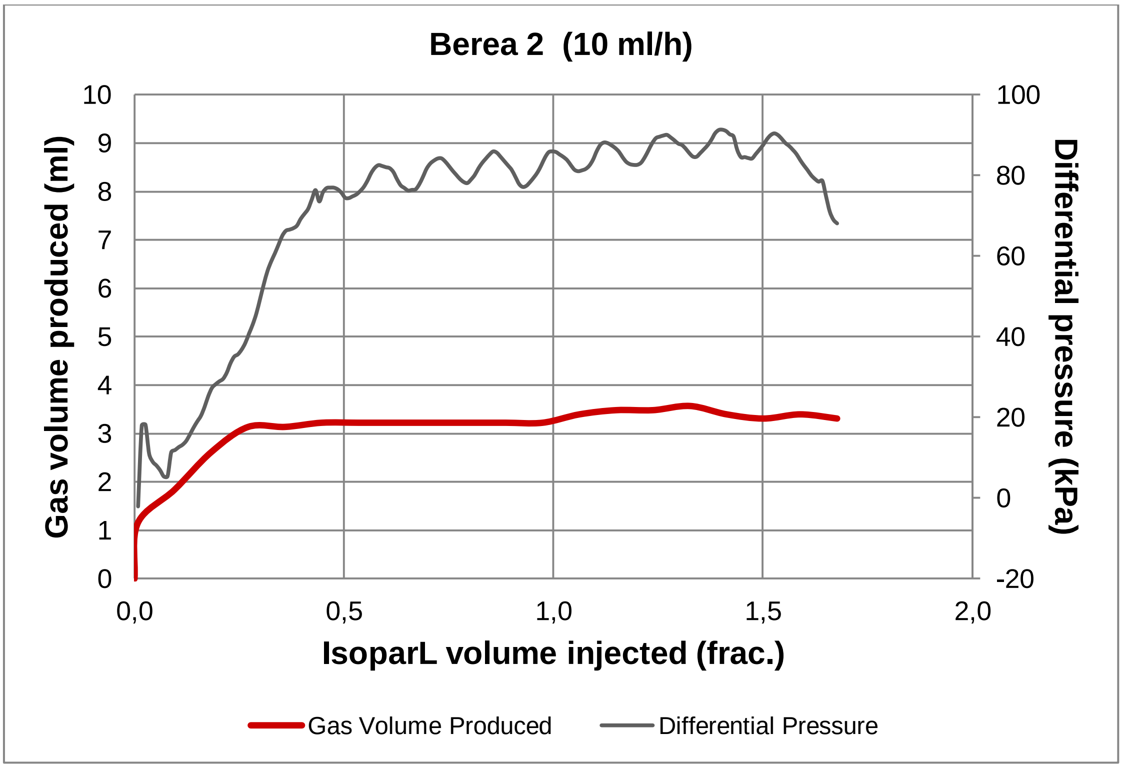


Fig. C - 16 - Gas volume produced at low rate injection, Berea 2

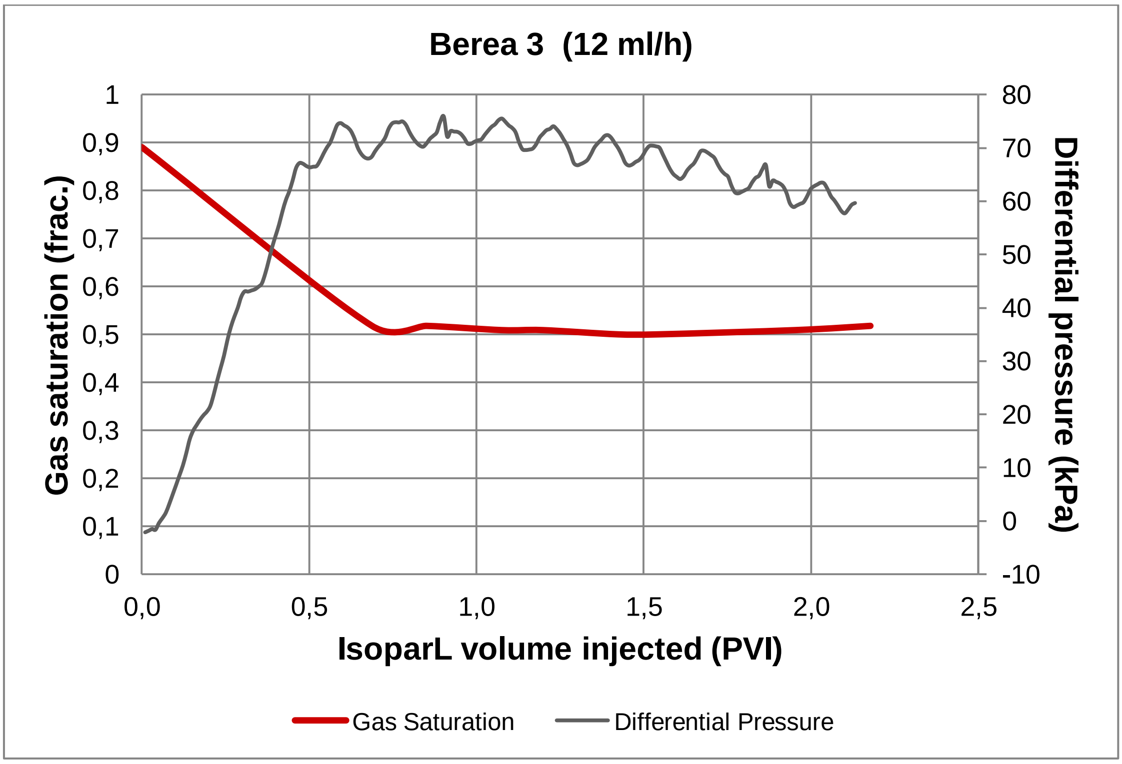


Fig. C - 17 – Gas saturation at low rate injectiom, Berea 3

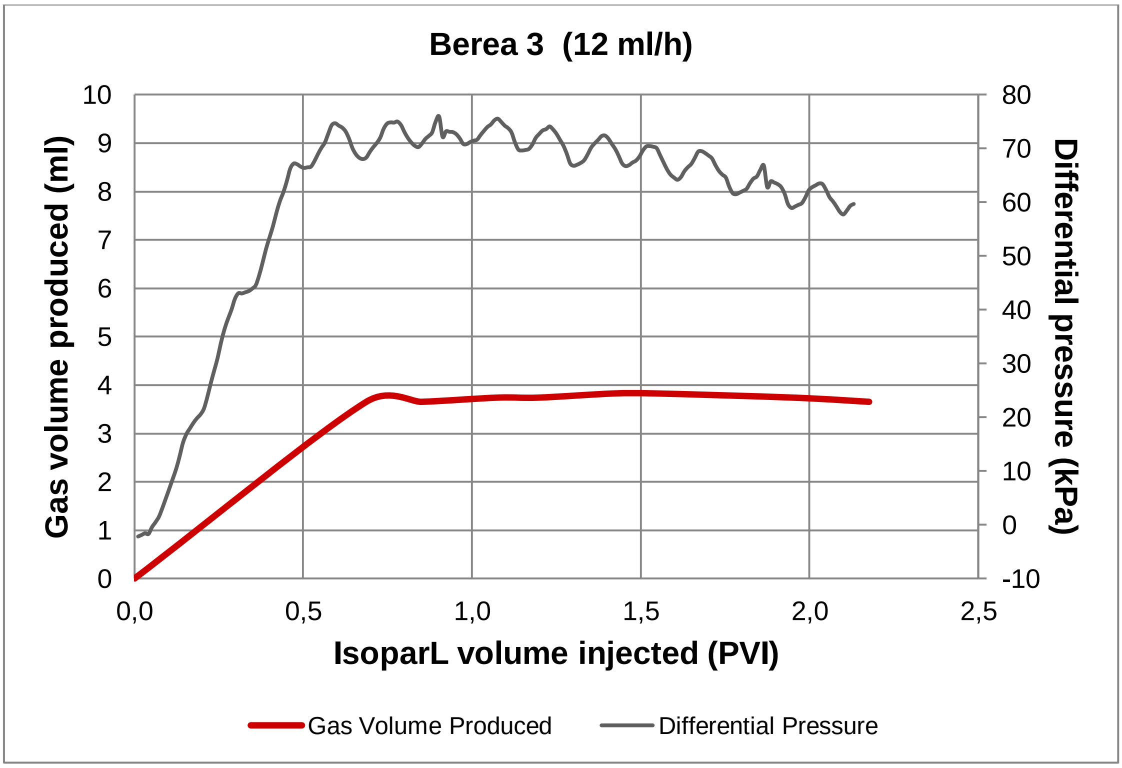


Fig. C - 18- Gas volume produced at low rate injection, Berea 3

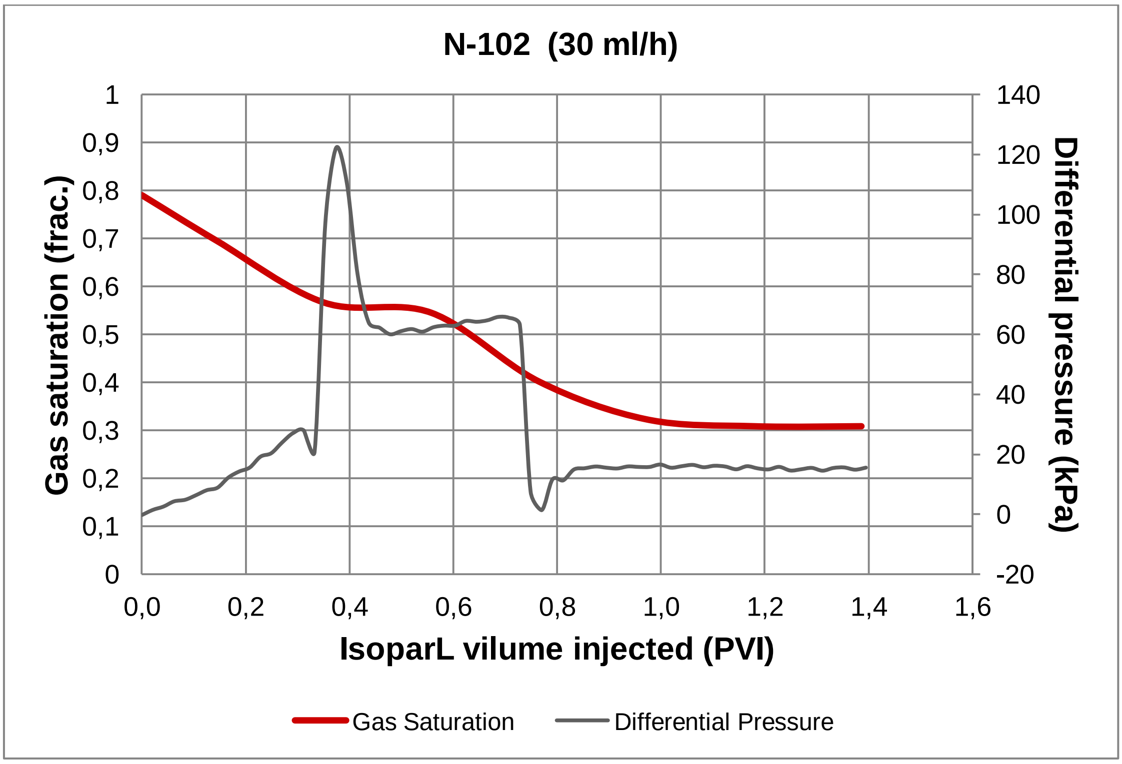


Fig. C - 19 – Gas saturation at low rate injectiom, N-102

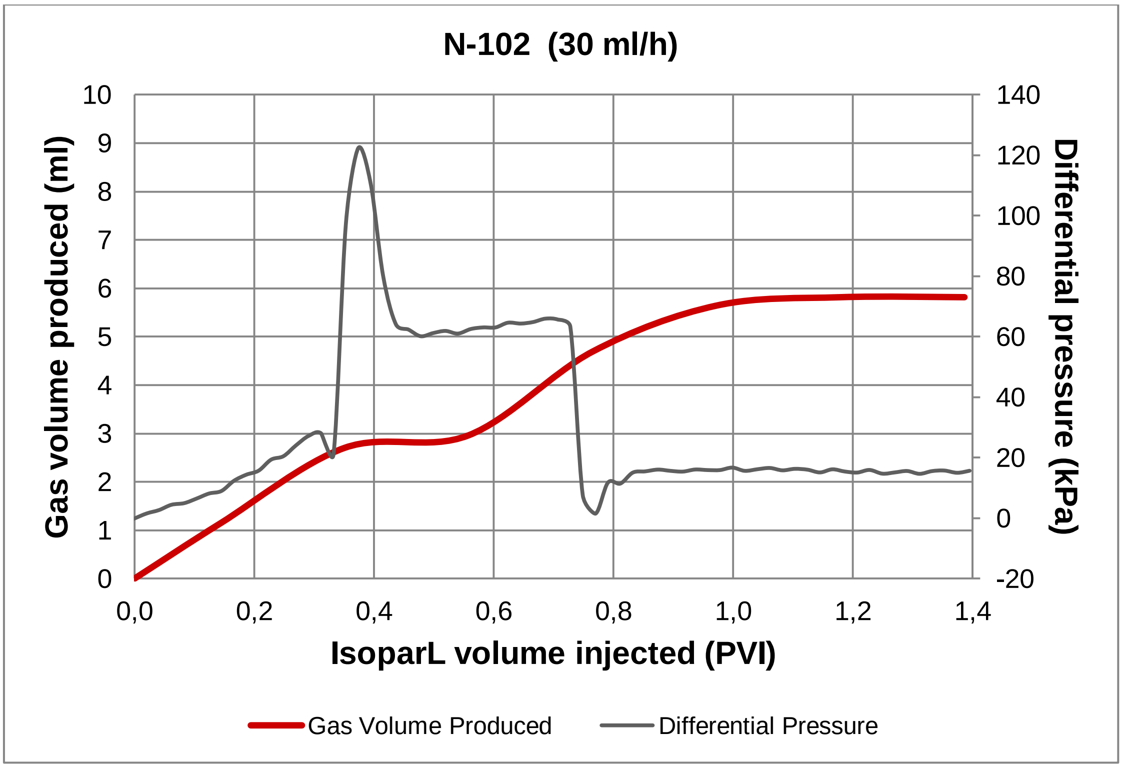


Fig. C - 20 - Gas volume produced at low rate injection, N-102

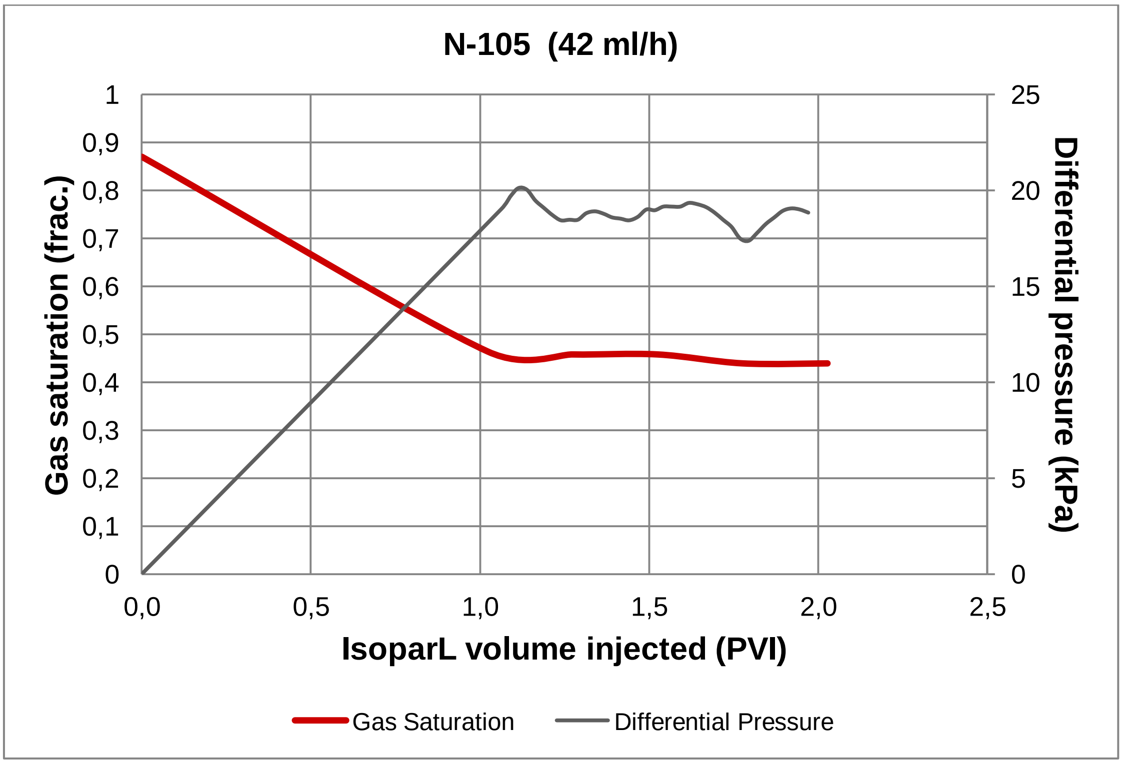


Fig. C - 21 – Gas saturation at low rate injectiom, N-105

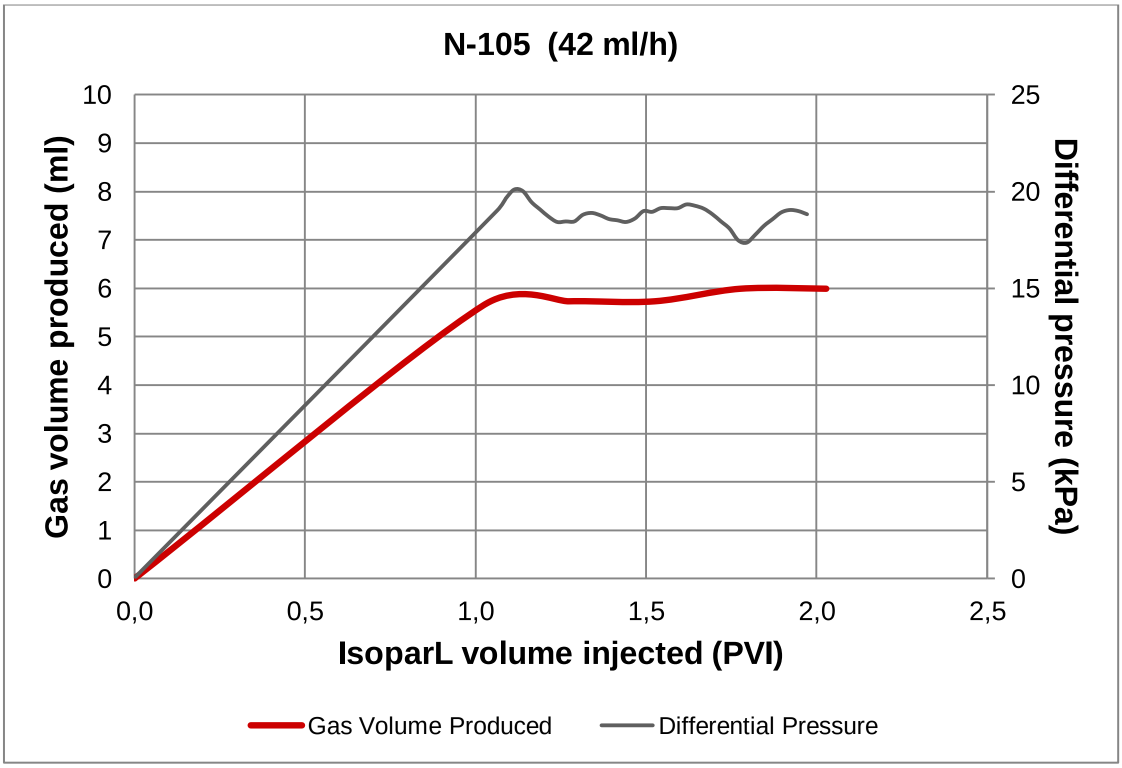


Fig. C - 22- Gas volume produced at low rate injection, N-105

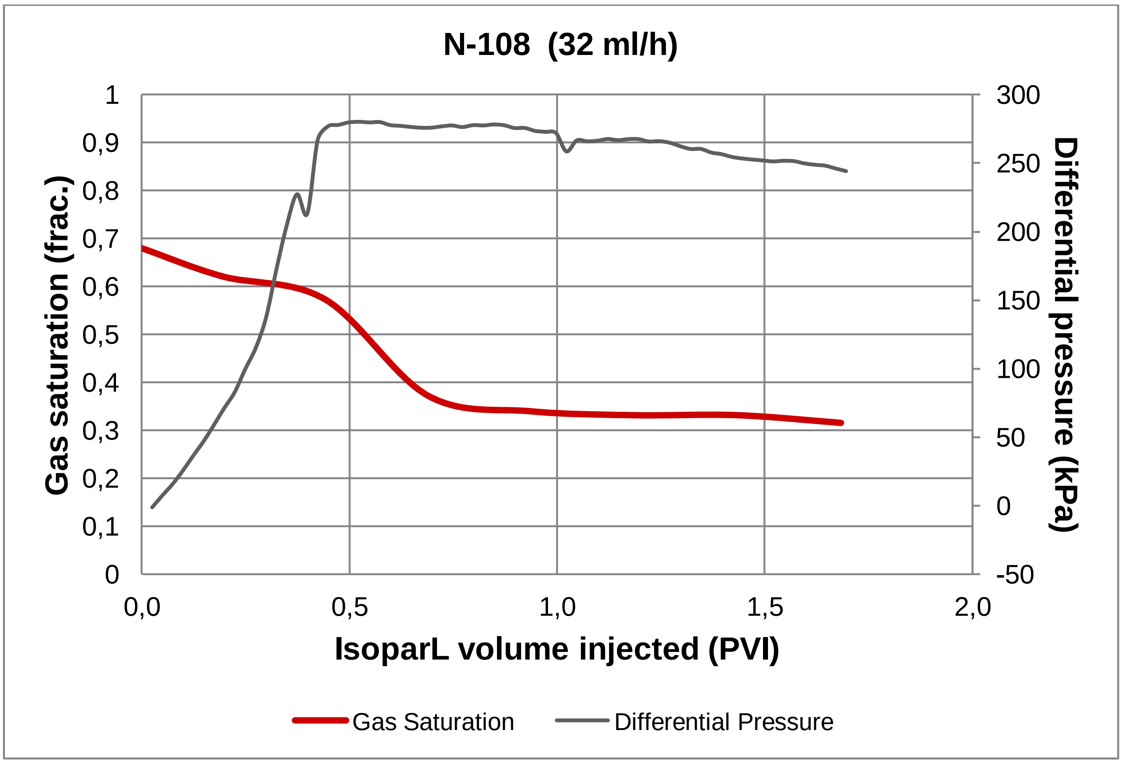


Fig. C - 23 – Gas saturation at low rate injectiom, N-105

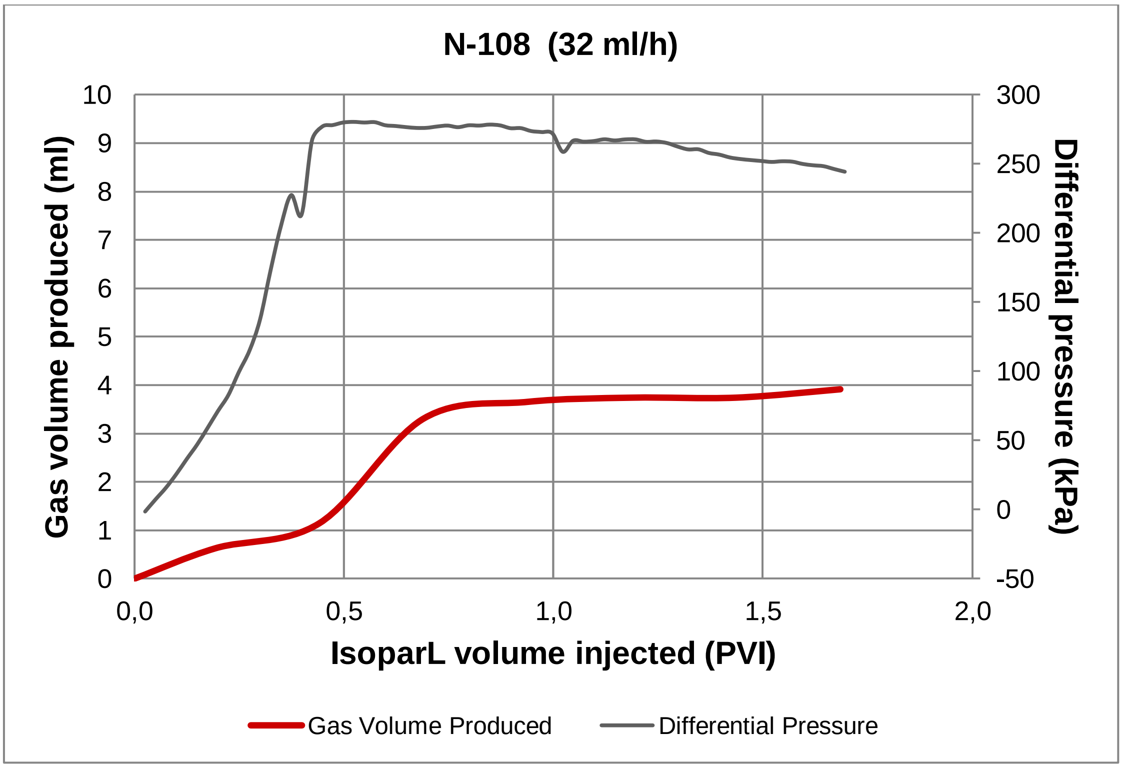


Fig. C - 24- Gas volume produced at low rate injection, N-108

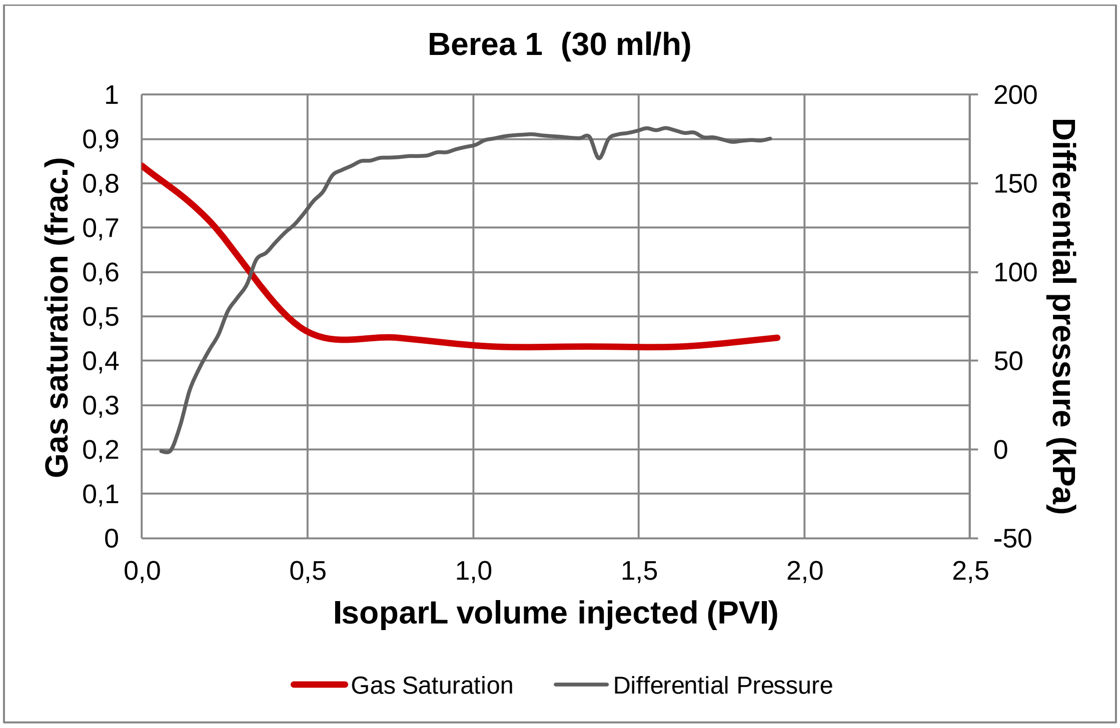


Fig. C - 25 – Gas saturation at low rate injectiom, Berea 1

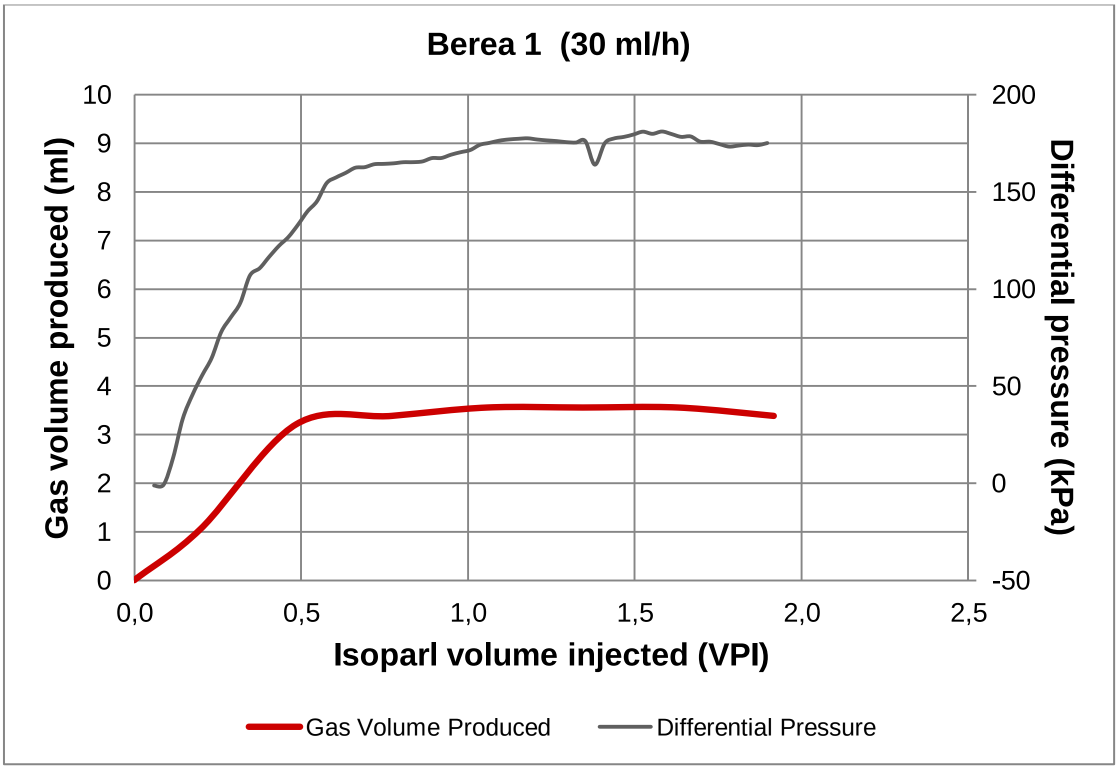


Fig. C - 26- Gas volume produced at low rate injection,Berea 1

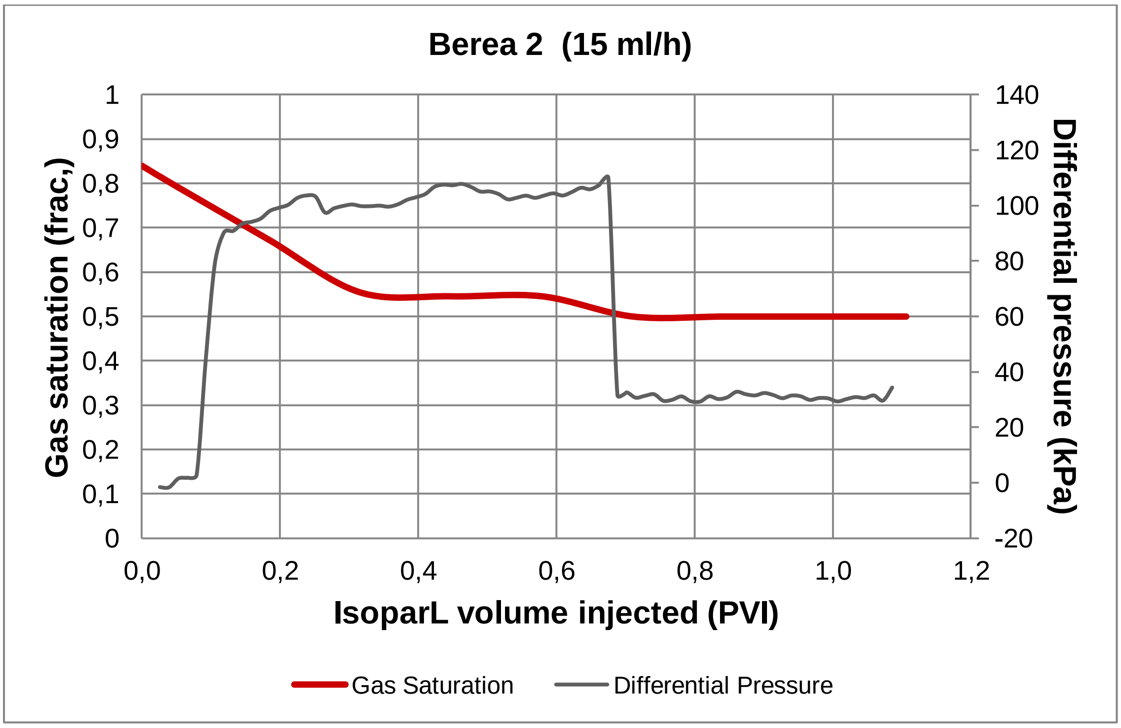


Fig. C - 27- Gas saturation at low rate injectiom, Berea 2

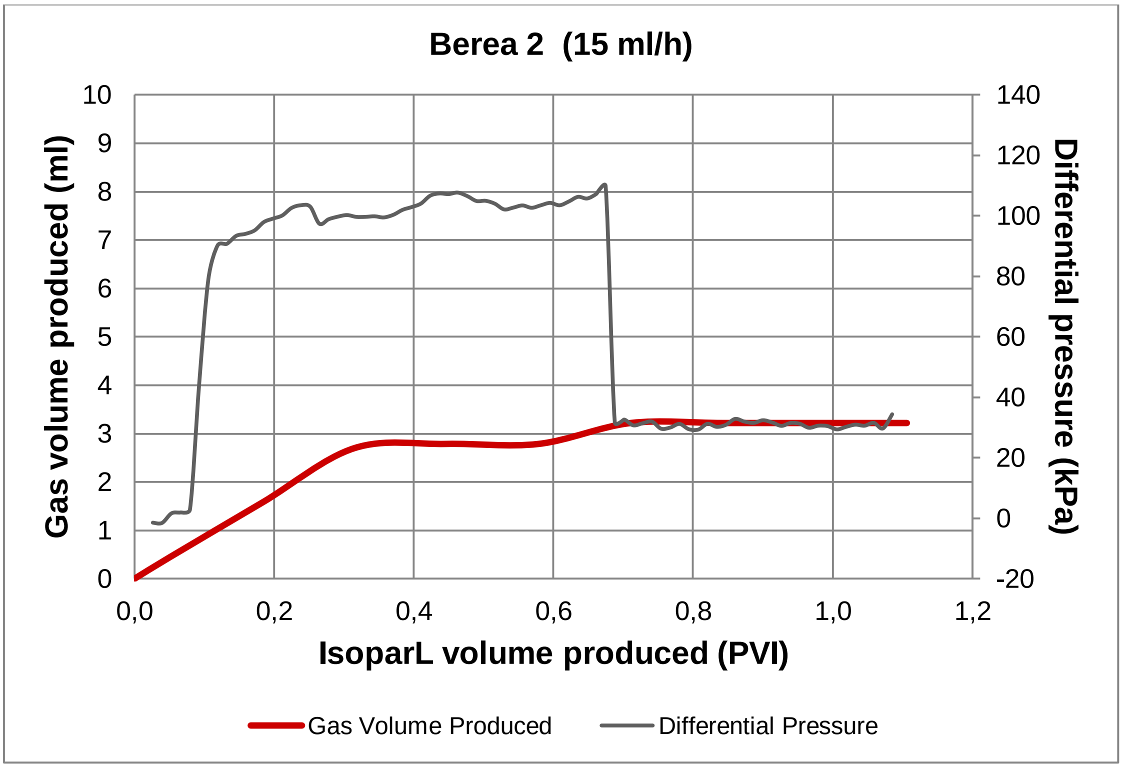


Fig. C - 28– Gas volume produced at low rate injection, Berea 2

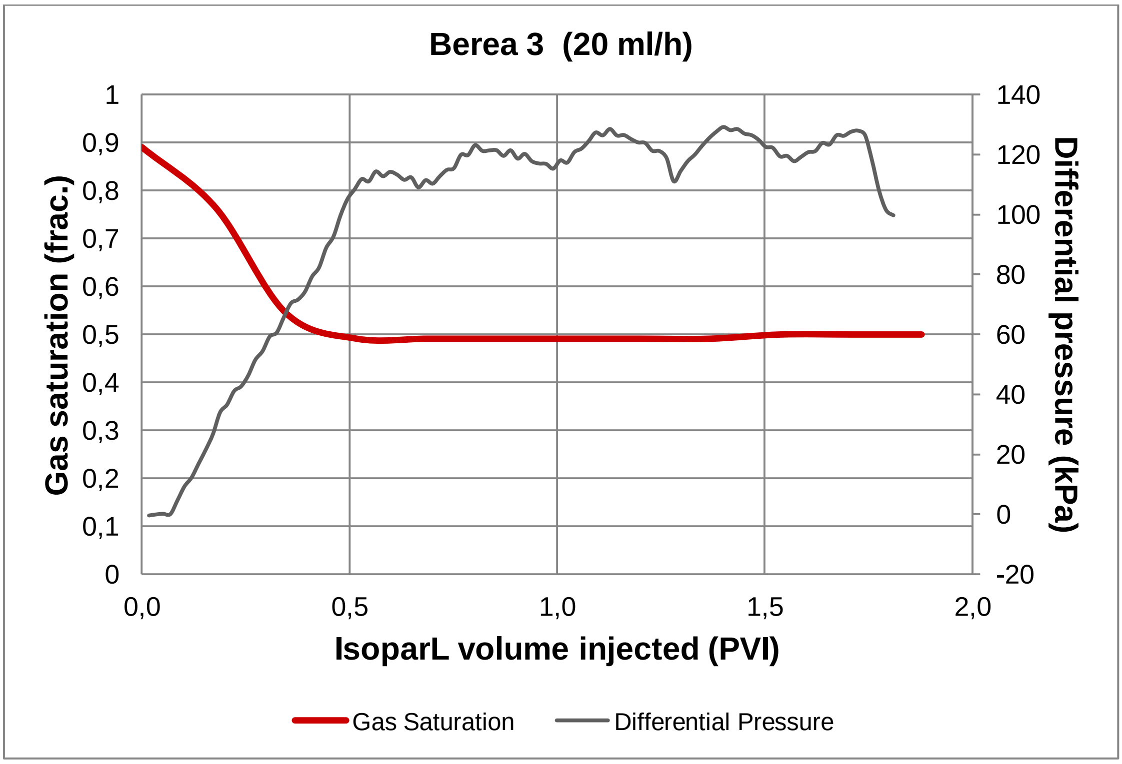


Fig. C - 29 – Gas saturation at low rate injectiom, Berea 3

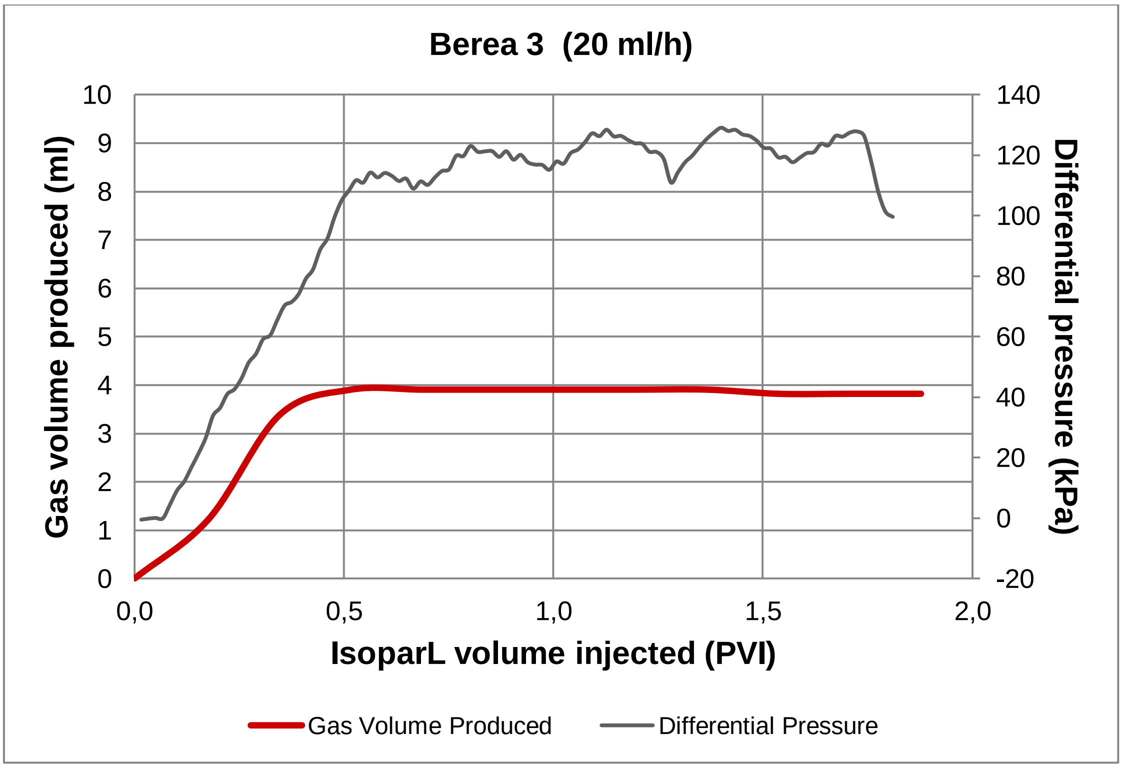


Fig. C - 30 – Gas volume produced at low rate injection, Berea 3

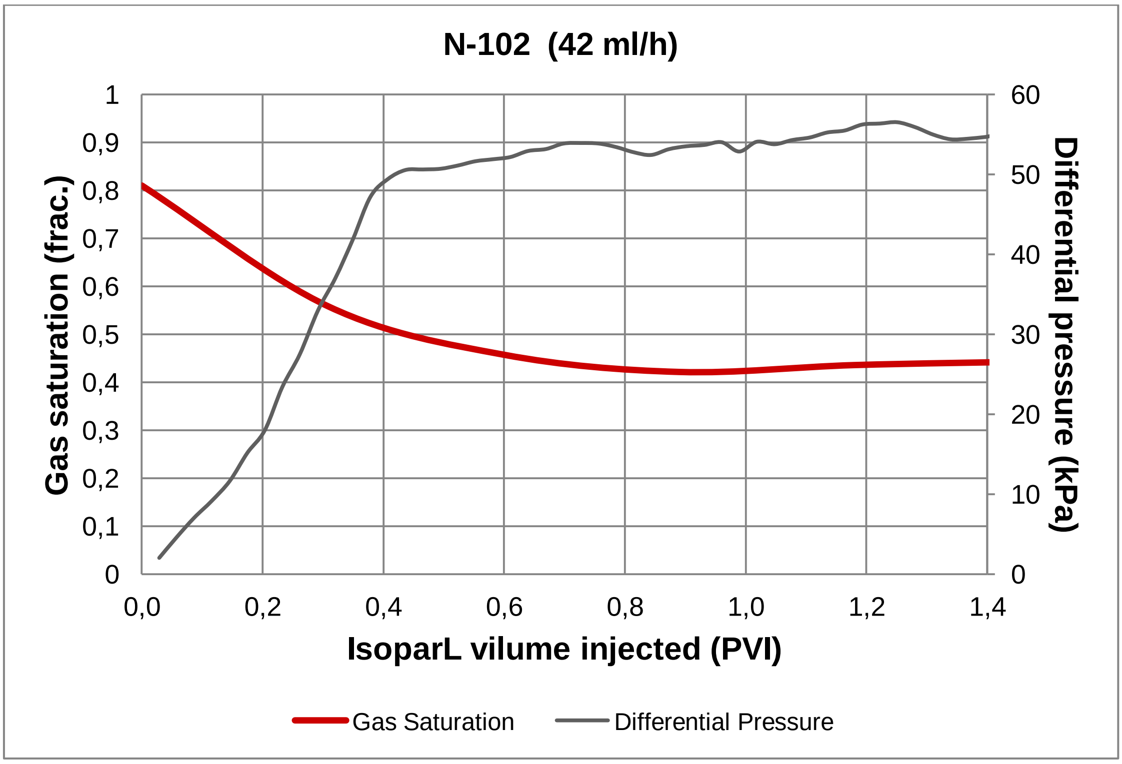


Fig. C - 31 . Gas saturation at low rate injectiom, N-105

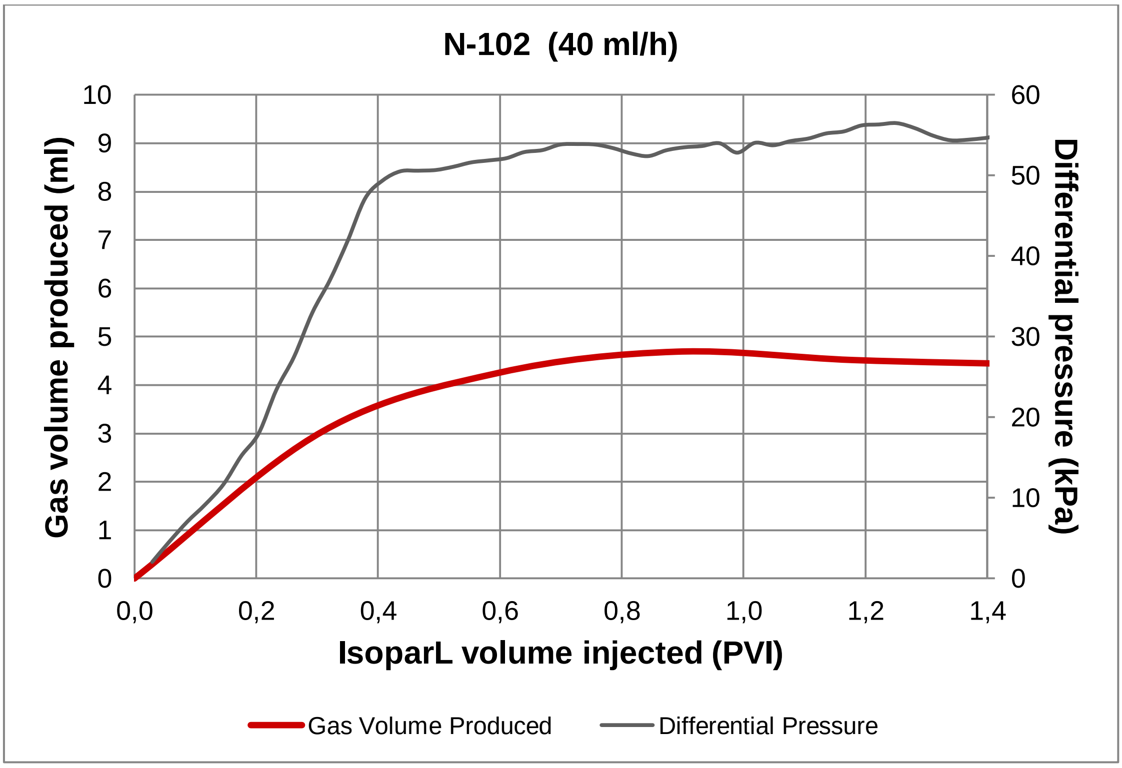


Fig. C - 32 – Gas volume produced at low rate injection, N-102

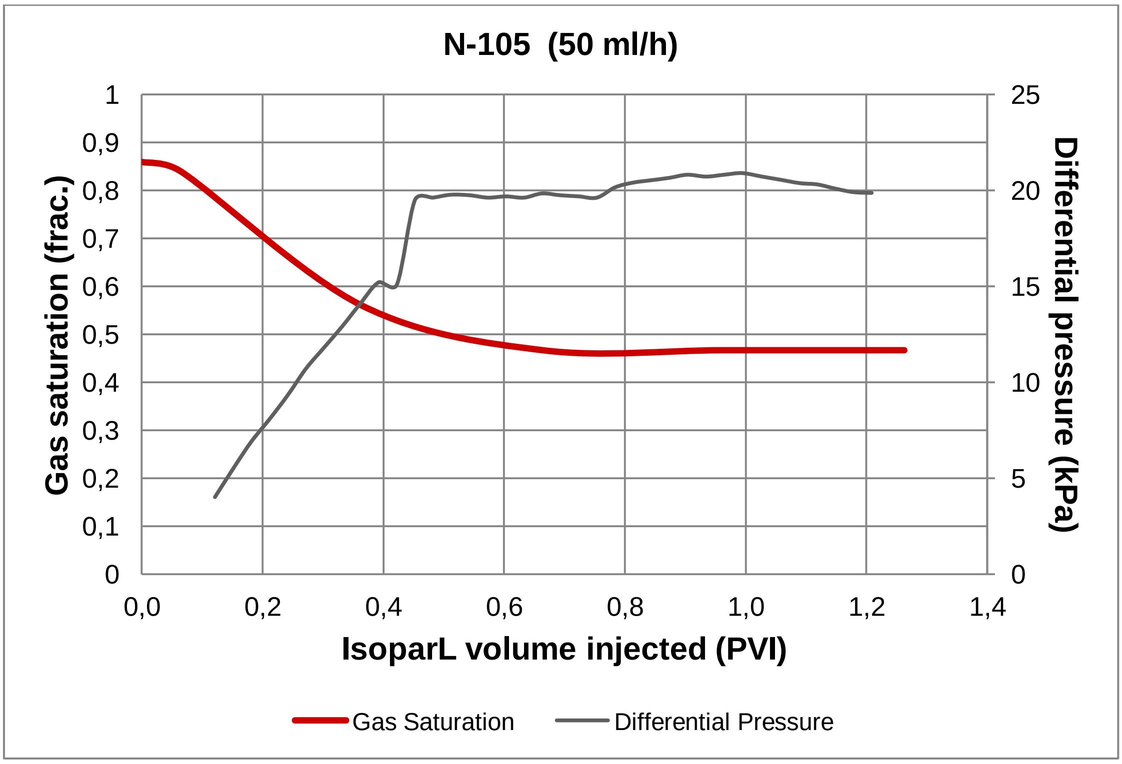


Fig. C - 33 – Gas saturation at low rate injectiom, N-105

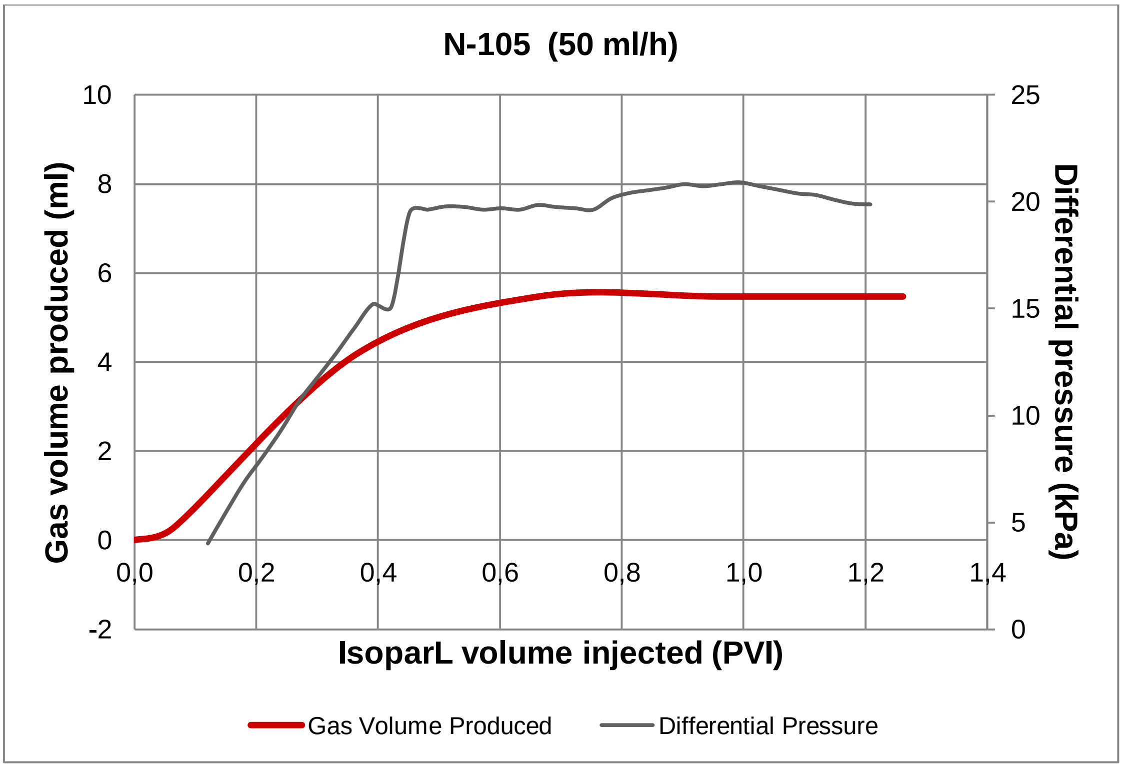


Fig. C - 34 – Gas volume produced at low rate injection, N-105

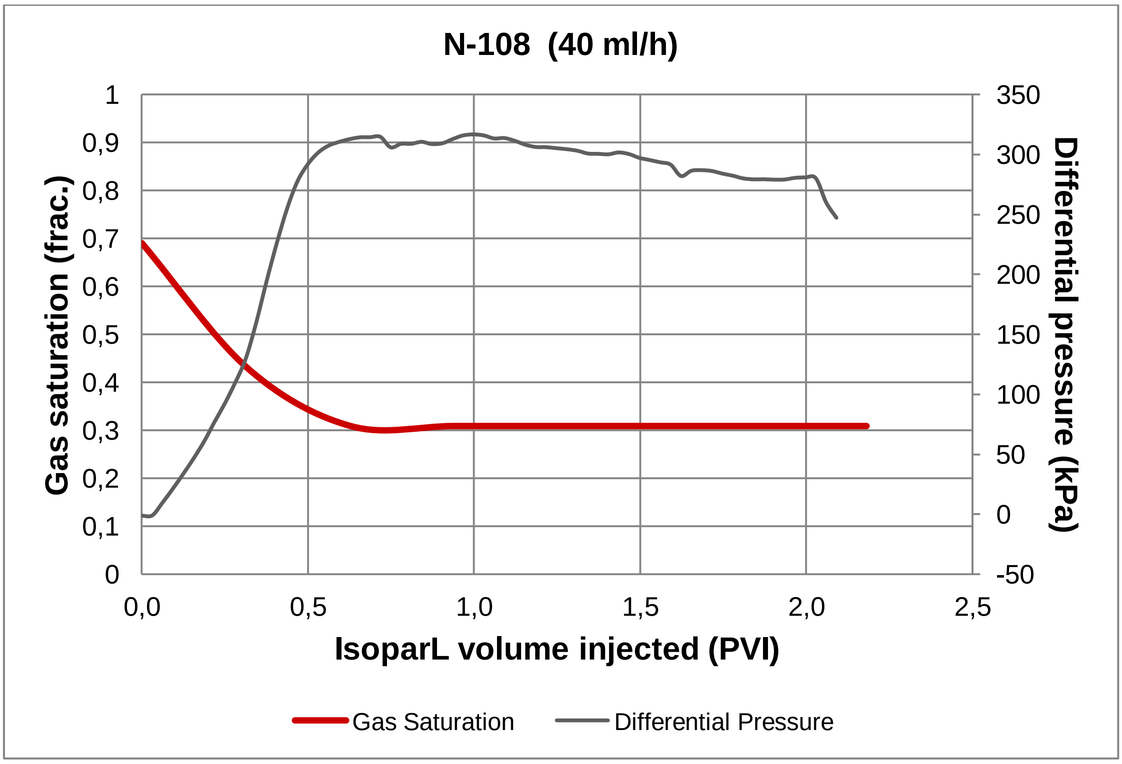


Fig. C - 35 – Gas saturation at low rate injectiom, N-108

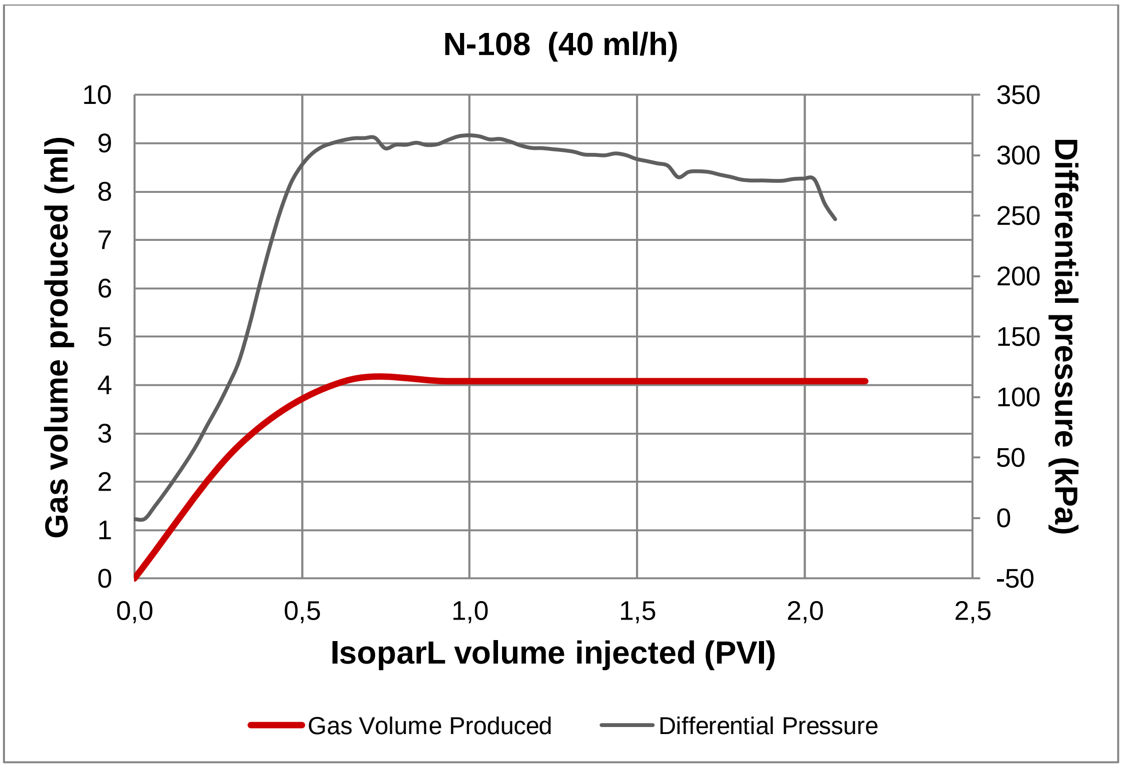


Fig. C - 36 - Gas volume produced at low rate injection, N-108

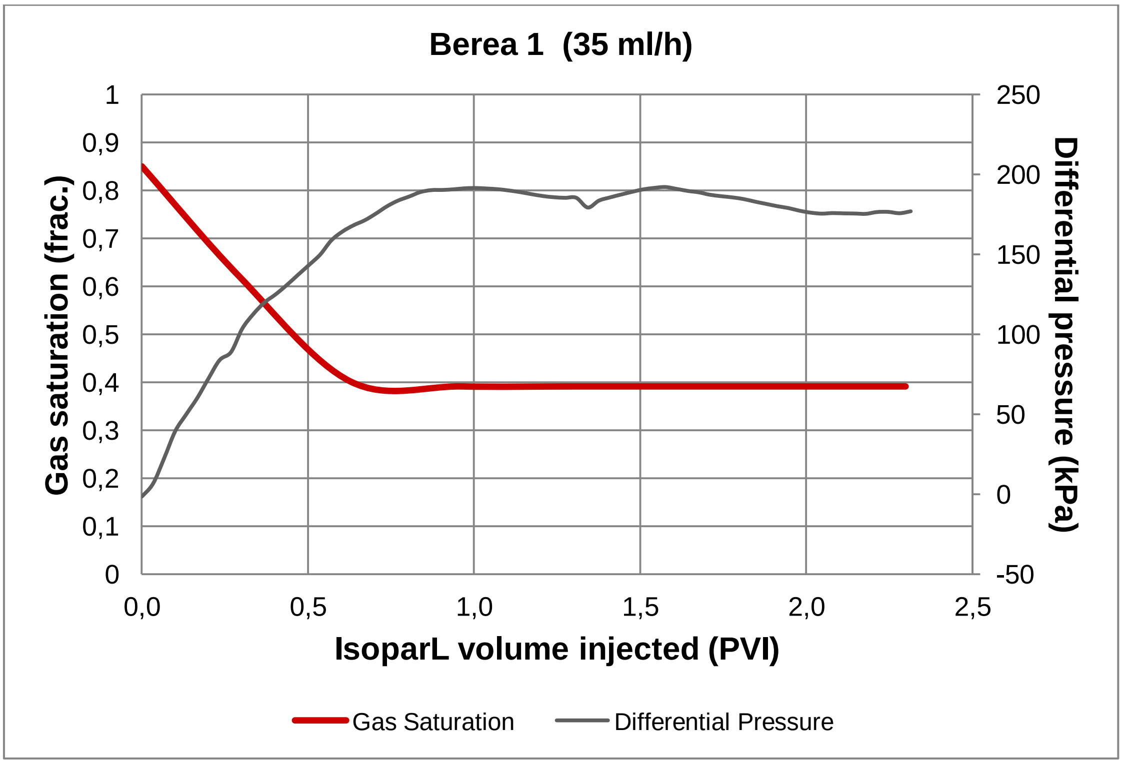


Fig. C - 37 – Gas saturation at low rate injectiom, Berea 1

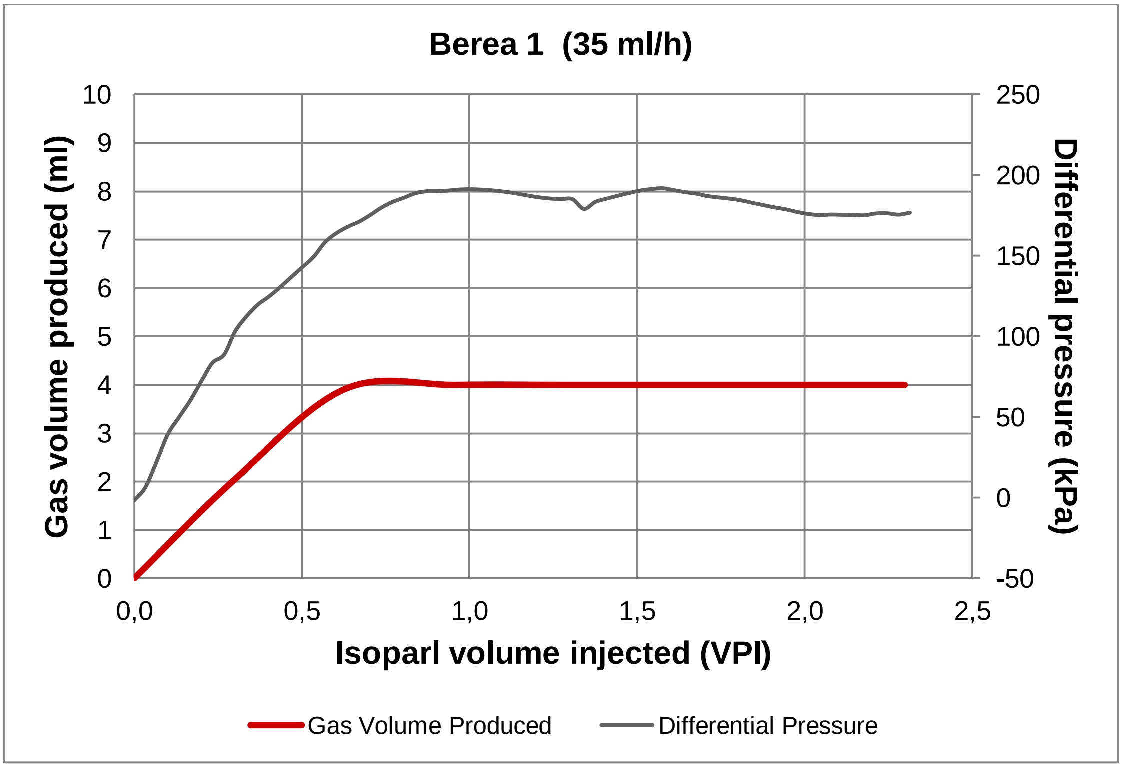


Fig. C - 38 – Gas volume produced at low rate injection, Berea 1

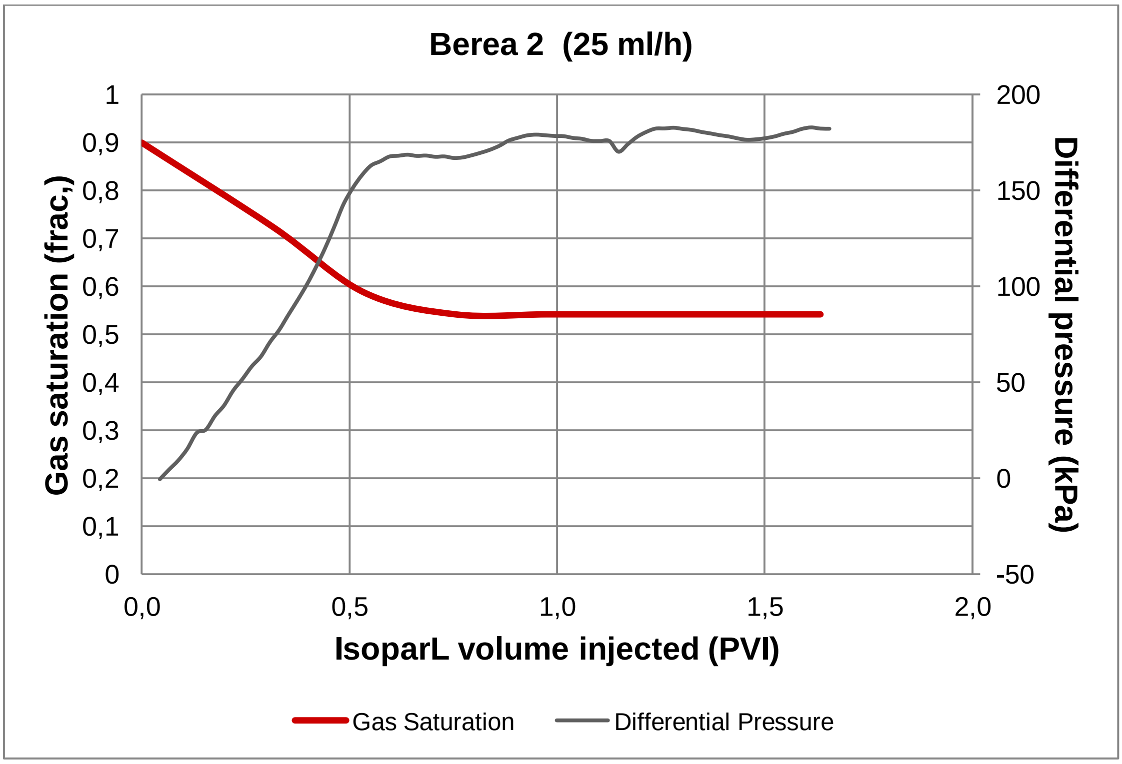


Fig. C - 39 – Gas saturation at low rate injectiom, Berea 2

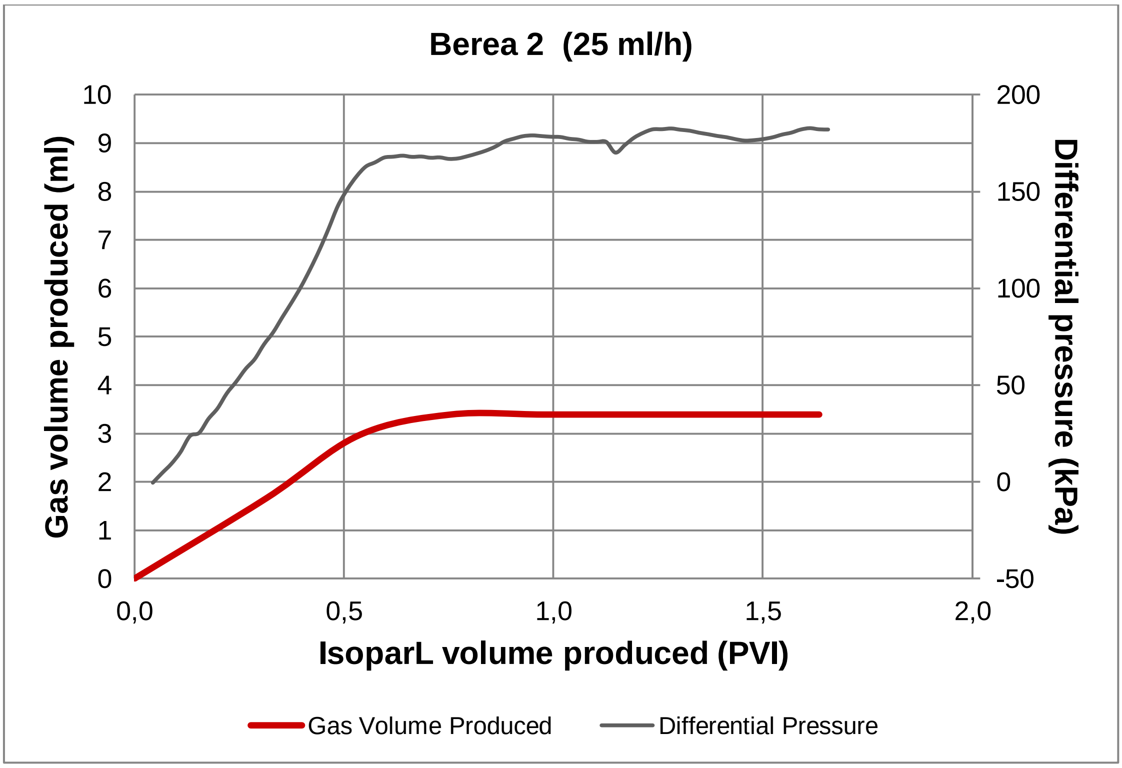


Fig. C - 40 – Gas volume produced at low rate injection, Berea 2

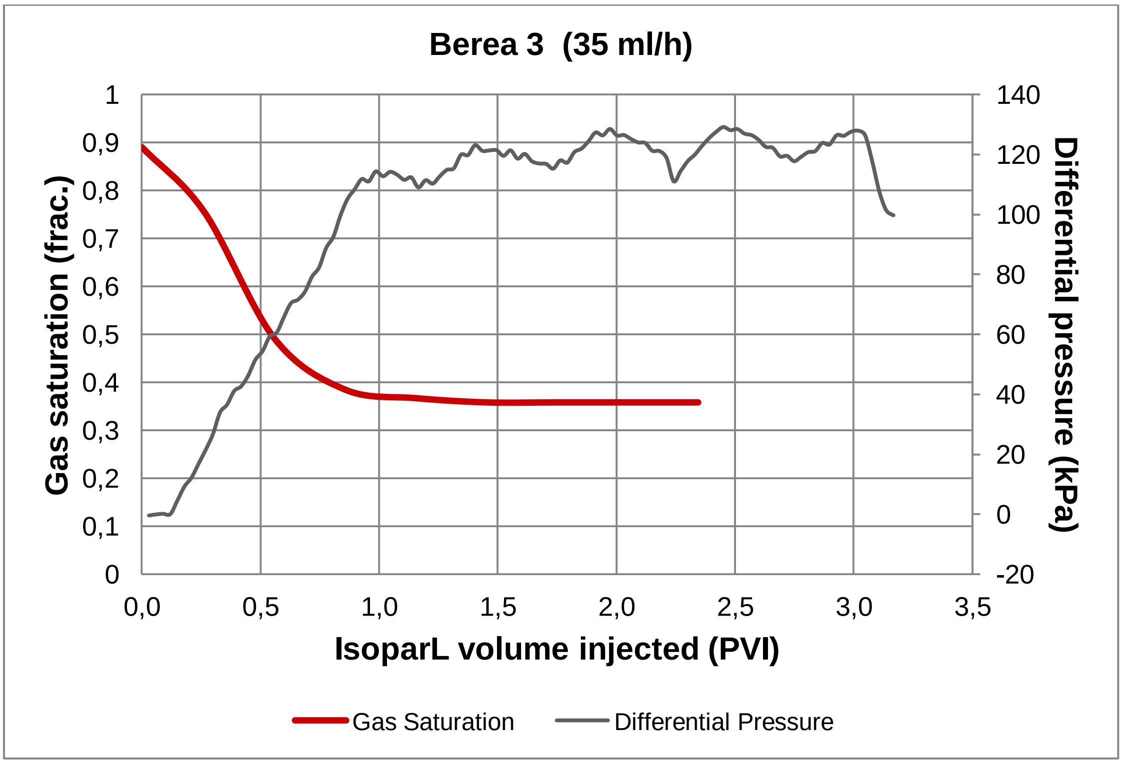


Fig. C - 41 – Gas saturation at low rate injectiom, Brea 3

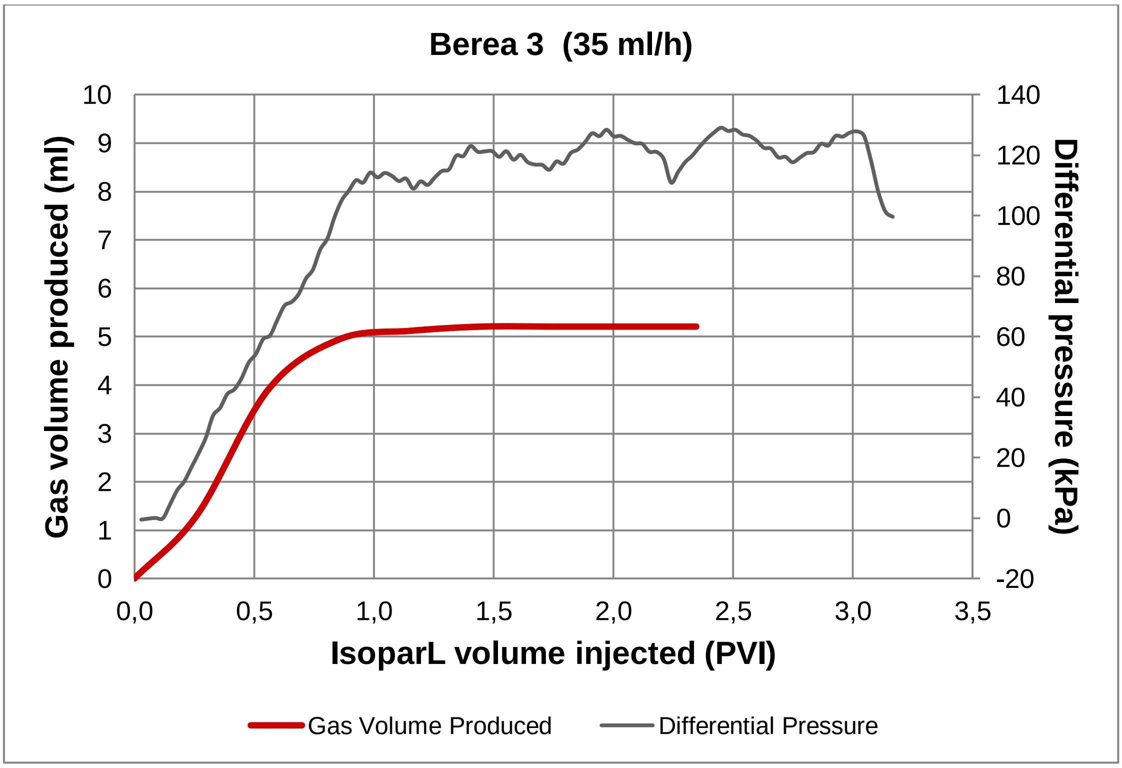


Fig. C - 42 - Gas volume produced at low rate injection, Berea 3

Appendix D – Data

D.1 Data Berea plugs

Table D - 1 – Basic data for Berea plugs

Base Measurements								
Density Isopar L	0,757	g/ml						
Plug ID	Weight dry	Weight saturated	Grain volume	bulkbolume	Weight IsoparL after saturation	Volume Isopar L after saturation	Pore volume	Ratio of Saturation
	(g)	(g)	(ml)	(ml)	(g)	(ml)	(ml)	
Berea 1	118	124,9	44,43	53,16	6,93	9,15	8,73	1,04
Berea 2	118,48	125,3	44,61	54,09	6,88	9,09	9,48	0,95
Berea 3	116,15	123,0	43,68	53,48	6,89	9,10	9,80	0,92

D.2 Data Satoil plugs

Table D - 2 – Basic data for the plugs received from Statoil

ID	Weight dry	Weight saturated	Height	pore volume factor	Pore volume
	(g)	(g)	(cm)		(ml)
N-102	108,66	118,73	4,814	0,70	12,07
N-105	99,45	109,90	4,803	0,76	13,92
N-108	112,04	120,34	4,848	0,62	10,73

D.3 USS

Table D - 3 - S_{gr} values calculated from weight difference

Residual gas saturation (from weights)

Plug ID	S_{gr}				
	Spontaneously imbibition	q = 4 ml/h	ΔP > 0	ΔP > 0	ΔP > 0
Berea 1	0,23	0,44	0,36	0,39	0,38
Berea 2	0,40	0,46	0,42	0,45	0,46
Berea 3	0,36	0,49	0,43	0,47	0,44
N-102	0,26	0,39	0,41	0,41	
N-105	0,28	0,43	0,47	0,42	
N-108	0,17	0,31	0,28	0,28	

Table D - 4 – S_{gr} values calculated from the burette value at the end of the experiments

Residual gas saturation at the end (from rig)

Plug ID	S_{gr}			
	q = 4 ml/h	ΔP > 0	ΔP > 0	ΔP > 0
Berea 1	0,50	0,45	0,43	0,39
Berea 2	0,51	0,46	0,50	0,54
Berea 3	0,55	0,5	0,49	0,36
N-102	0,43	0,31	0,42	
N-105	0,44	0,44	0,47	
N-108	0,39	0,32	0,31	