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Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay–Kuparuk River Area on the North Slope of Alaska

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Abstract

Natural gas hydrates have long been considered a nuisance by the petroleum industry. Hydrates have been hazards to drilling crews, with blowouts a common occurrence if not properly accounted for in drilling plans. In gas pipelines, hydrates have formed plugs if gas was not properly dehydrated. Removing these plugs has been an expensive and time-consuming process. Recently, however, due to the geologic evidence indicating that in situ hydrates could potentially be a vast energy resource of the future, research efforts have been undertaken to explore how natural gas from hydrates might be produced.

This study investigates the relative permeability of methane and brine in hydrate-bearing Alaska North Slope core samples. In February 2007, core samples were taken from the Mt. Elbert site situated between the Prudhoe Bay and Kuparuk oil fields on the Alaska North Slope. Core plugs from those core samples have been used as a platform to form hydrates and perform unsteady-state displacement relative permeability experiments. The absolute permeability of Mt. Elbert core samples determined by Omni Labs was also validated as part of this study. Data taken with experimental apparatuses at the University of Alaska Fairbanks, ConocoPhillips' laboratories at the Bartlesville Technology Center, and at the Arctic Slope Regional Corporation's facilities in Anchorage, Alaska, provided the basis for this study.

This study finds that many difficulties inhibit the ability to obtain relative permeability data in porous media-containing hydrates. Difficulties include handling unconsolidated cores during initial core preparation work, forming hydrates in the core in such a way that promotes flow of both brine and methane, and obtaining simultaneous two-phase flow of brine and methane necessary to quantify relative permeability using unsteady-state displacement methods.

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Chapter 1

1.1 Introduction

The Alaska North Slope is one of the largest regions of arctic petroleum exploration and production in the world. The discovery of oil at Prudhoe Bay in the 1960s triggered much of this development including that of the Trans Alaska Pipeline System (TAPS), one of the world's largest private engineering projects. While still a cornerstone of production, Prudhoe Bay is in decline, and to maintain operation of the TAPS, fields such as Kuparuk, Milne Point, and Alpine have also been developed.

Many years have passed since the opening of Prudhoe Bay, and the petroleum industry in other regions of the world has diversified to include ever-expanding development of natural gas resources in addition to crude oil. Natural gas, being an inexpensive and easy way to produce electricity, heat buildings, and even power motor vehicles, is seen as a resource that could provide nations with another energy source to contribute towards desired energy security in an environment of tension between producing and consuming countries. Work is currently underway by competing interests to build a natural gas pipeline from the Alaska North Slope into southern Canada.

1.2 Methane Hydrates

The energy density of hydrates is something that has commanded much attention in recent years. One volume of gas hydrate has been shown to contain up to 180 volumes of gas at standard conditions. Additionally, unlike the differences between crude oil and natural gas, the differences between gas from hydrate and gas from conventional reservoirs ends at the wellhead. The key to developing hydrates as a resource lies in the characteristics of the reservoir during production.

Gas hydrates are solid crystalline structures of water and gases—often methane, the main constituent of natural gas. They are thermodynamically stable at relatively low temperatures and high pressures and exist onshore in the Arctic and in offshore environments. Arctic onshore hydrates are seen as the easiest to produce logistically, given the high costs and technical challenges of offshore drilling. However, this has not stopped relatively energy-poor countries

such as Japan and India from investing significant sums of money in determining ways to produce these unconventional resources to reduce their dependence on imports. In North America, however, pilot projects have been confined to arctic regions of Alaska and Canada. In arctic onshore environments, hydrates exist below the permafrost and above where conventional hydrocarbon resources are found, because significant overburden pressure and low-enough temperatures at depth promote thermodynamic stability of hydrates.

To date, natural gas dissociated from hydrates has been observed to contribute positively to the production of two commercial-scale gas fields in the Arctic: the Messoyakha field in Siberia (Collett and Ginsberg, 1998) and the gas field surrounding the Alaskan village of Barrow (Singh, 2008). Both fields are still actively producing gas. In both cases, dissociating hydrates, which contribute to cumulative production, were not planned but were arrived at by accident. These reservoirs show the classic arrangement of a gas reservoir capped by hydrates. As natural gas was produced over time, reservoir pressure declined below the hydrate's stability pressure, which caused it to dissociate, replenishing some of the gas lost to production. By maintaining this higher-than-normal reservoir pressure, these fields have experienced far greater yields than could have been recovered without the presence of hydrates.

1.3 Objectives

This study was conducted to determine the relative permeability characteristics of methane hydrate systems and the base permeability of unconsolidated sediments that are typical of reservoirs containing in-situ hydrates on the Alaska North Slope.

Executive Summary

Gas hydrates are a large potential energy source for the future. Natural gas dissociated from hydrates is no different from natural gas not stored in hydrates. Therefore, this unconventional resource does not require retooling of any end uses for natural gas, unlike unconventional resources such as heavy oil, which require modification of refineries. It is generally accepted that quantities of gas hydrates found in oceanic conditions far exceed those found in permafrost conditions in arctic environments. These two quantities were most recently estimated at $7.4 * 10^{14} \text{ m}^3$ for permafrost hydrates and $2.1 * 10^{16} \text{ m}^3$ for oceanic hydrates (MacDonald, 1990). Recent estimates published by the U.S. Geological Survey (USGS) indicate that the Alaska North Slope contains approximately 85 trillion cubic feet of technically recoverable natural gas from gas hydrates (http://www.doi.gov/news/08_News_Releases/111208.html).

Hydrates have their own unique challenges. Gas present in hydrates is locked away in an immobile phase that requires dissociation by a variety of means. If gas is produced, significant amounts of water would also be released which would flow towards the production well in any number of scenarios. One of the ways to quantify this behavior is through the relative permeability of these two phases in the presence of hydrates. The present research project seeks to further define the relative permeability characteristics of these hydrate systems.

This project, which has been funded by the U.S. Department of Energy and supported through collaboration with industry members such as BP and ConocoPhillips, seeks to provide the most realistic relative permeability data for in situ hydrate systems to date. Unlike previous studies, this project uses core samples that contained hydrates prior to being liberated to the surface. Past research used core samples that not once were influenced by the presence of gas hydrates and, therefore, reflected to a lesser degree the true character of these systems.

The experimental apparatuses used in this study were developed and/or modified for use at the University of Alaska Fairbanks. Experimental apparatuses allowed the researchers to form hydrates in core samples and then flow either methane gas or brine through the sample. Work at the Bartlesville Technology Center afforded the use of a magnetic resonance imager (MRI) to track the formation of hydrates within core samples.

Work conducted in Anchorage, Alaska, consisted of using a probe permeameter to measure the core samples' permeability to air. This work served to validate work done by Omni Labs to quantify absolute permeability of Mt. Elbert core samples.

Relative permeability measurements in Mt. Elbert core samples with the presence of gas hydrates has yet to be accomplished in a variety of technical challenges. Findings suggest that correlating relative permeability measurements obtained in sandstone cores may prove more fruitful.

Chapter 2

This chapter discusses knowledge fundamental to understanding hydrates and permeability experiments. Topics include hydrate formation and dissociation principles as well as methods for determining parameters such as relative permeability and absolute permeability in core samples.

2.1 Hydrate Formation

Hydrate formation is a reaction between water and gas molecules under certain specific environmental conditions, namely temperature and pressure. In the petroleum industry, two main types of hydrates are often considered: natural gas (mostly methane) hydrates and carbon dioxide hydrates. Methane hydrates can form hydrate plugs in natural gas facilities and are present during drilling operations, often overlying other hydrocarbon intervals of interest. Carbon dioxide hydrates have also been investigated as a method for storing carbon dioxide in order to mitigate its release into the atmosphere and as a way to stimulate production of methane hydrates.

Sloan and Koh (2008) describe initial hydrate nucleation (formation) in four discrete steps. The first involves a process similar to that when water forms into ice. Water molecules begin to arrange themselves according to their slight positive and negative polarities. The second step consists of partially formed crystals. When gas molecules are present partially within these cage structures, fully formed crystals form nearly instantaneously. The third step involves hydrate crystals forming alongside each other by sharing facies with one another. This step allows for the reduction in number of water molecules required to contain each gas molecule. This step inherently requires less energy than individual hydrate cages would require. The fourth and final step of nucleation is when clusters of hydrates agglomerate to a critical size and continue to grow.

2.1.1 Formation of Hydrates In Situ

Hydrate formation in consolidated and unconsolidated samples adheres to the same principles as hydrate formation in bulk quantities, but is influenced by other factors, such as grain size, porosity, and rock wettability. Westervelt (2004) conducted a study that compared

pressure and temperature deviations between hydrates in bulk and hydrates in core samples. It was found that higher pressure and lower temperatures, when compared with formation in bulk, are generally required to form hydrates in core samples.

For the purpose of this study, precise equilibrium conditions for hydrates were not stressed. Rather, it was desired that hydrates would be formed in the porous media over manageable amounts of time, often less than one day, to facilitate timeliness of the individual experiments. Pressure and temperature conditions, therefore, were set so that the core sample, saturated with water and gas, was well within the hydrate-equilibrium envelope.

2.2 Hydrate Dissociation

Gas molecules are trapped in hydrate lattice structures for two fundamental reasons. Firstly, low temperatures promote the formation of water cages held together by van der Waals forces. These cages form much like ice and contain void spaces at their centers, which decrease their density. Secondly, high pressures effectively force individual gas molecules into open spaces present in the cages.

In the natural gas industry, interest in hydrates requires knowledge of how methane would potentially be liberated from hydrates. External energy inputs must be supplied to hydrates in order for them to dissociate. The three main concepts related to hydrate dissociation are depressurization, thermal (heat) addition, and thermodynamic inhibitors, which alter the temperature and pressure conditions at which hydrates can exist. For dissociation, either one of these two forces—temperature and pressure—must be overcome. Thermal addition and thermodynamic inhibitors, such as methanol, effectively break the ice structure of the hydrate crystals. Depressurization causes the gas molecules trapped in hydrates to be released from the cages.

Dissociating hydrates produce two fluids: water and its associated gas. Field level production of gas, therefore, also produces water under any of these production schemes. In order to understand how quickly these fluids will flow towards a wellbore with time, an understanding of relative permeability of gas and water in the presence of various hydrate saturations is necessary.

2.3 Methods for Determining Relative Permeability

Relative permeability is a key reservoir parameter for those investigating production techniques for a given field, reservoir, or zone. Relative permeability is the permeability of two simultaneously moving fluids, often oil and water, but sometimes oil, water, and gas, as well as gas and water.

The relative permeabilities of each fluid are reported relative to base permeability (at the other fluid's irreducible saturation) at a given saturation. Normally the saturation is that of the wetting fluid. The wetting fluid, which for most reservoirs is water, preferentially contacts the reservoir rock as opposed to other fluid. This means that no matter how much of the non-wetting phase is flowing over an extended period of time, saturation of the wetting phase will not be reduced past its irreducible saturation.

Determination of a complete data set for water and gas flow in the presence of hydrates is complicated because this data is likely to change with differing hydrate saturations. Therefore, relative permeability data must be known for a variety of hydrate saturations.

The following section will discuss some of the common laboratory techniques for determining relative permeability in core samples.

2.3.1 Steady-State Technique

The steady-state technique involves simultaneous injection of two phases at set volumetric ratios into a porous media. When pressure drop across the core and the injected ratio of the fluids is the same as that observed at the outlet, the system is said to be at steady-state condition, Dandekar (2006).

The procedure for this technique dictates that a core sample should begin with 100% water saturation. The volumetric ratio of each fluid is varied during each iteration to generate a complete data set over a range of fluid saturations. Calculation of the effective permeability for each phase can usually be determined according to Darcy's law (in this case for water):

$$k_{w,eff} = \frac{q_w \mu_w L}{\Delta P_w A} \quad (2.1)$$

where

k = Permeability (darcy)

μ = Viscosity (centipoise)

q = Flow rate (cc/sec)

L = Length of flow (cm)

A = Cross-sectional area of flow (cm²)

ΔP = Pressure difference (atmospheres)

Experimental procedures for determining relative permeability with the steady-state technique are often time-intensive and the technique's main drawback. However, once steady-state conditions have been met, the calculations for determining relative permeability are quite simple.

In the context of gas-water permeability in the presence of hydrates, use of this method could be especially risky and prone to a variety of errors. The main difficulty is how to maintain a certain saturation of hydrates over the duration of an experiment. This necessitates a fine and difficult balance between preventing dissociation of the pre-existing hydrates and preventing formation of additional hydrates from the two mobile phases. Hydrate formation has been shown to be a time-dependent process, hence, does not happen instantaneously; but given the long duration of steady-state experiments, it is still worthy of concern.

2.3.2 Unsteady-State Technique

In terms of ease of the physical experiment and ease of calculations, the unsteady-state method is the exact opposite of the steady-state method. It is easier and quicker to perform with the same laboratory setup, yet requires many more calculations and assumptions to determine permeabilities Dandekar (2006).

The unsteady-state method involves displacement of one fluid (usually the non-wetting phase) by another (usually the wetting phase) and measurement of production rates at the outlet of the core. As the wetting phase is injected, displacing the non-wetting phase, the wetting phase's saturation increases from its irreducible saturation to the non-wetting phase's irreducible saturation.

The common method for analyzing data generated by this type of experiment is the Johnson-Bossler-Naumann (1959) method. Data that must be recorded include quantities of produced and injected fluids, up and downstream pressures, fluid viscosities, and physical characteristics of the core sample such as bulk dimensions and porosity.

The method will not be fully derived in this report. The simplified equations of interest are as follows:

$$k_{rw} = k_{rw,max} I_r^2 \frac{dQ_{wp}}{d(Q_{gi} I_r)} \quad (2.2)$$

$$k_{rg} = k_{rw} \frac{\mu_w}{\mu_g} \frac{(1 - \frac{dQ_{wp}}{dQ_{gi}})}{\frac{dQ_{wp}}{dQ_{gi}}} \quad (2.3)$$

where

k_{rw} = Relative permeability of water (ratio)

k_{rg} = Relative permeability of gas (ratio)

Q_{wp} = Flow rate of produced water (pore volume)

Q_{gi} = Flow rate of injected gas (pore volumes)

$I_r = \frac{(\frac{u}{P})}{(\frac{u}{P})_i}$ = Relative injectivity (ratio), where $u = Q/A =$ average velocity of fluid

2.3.3 Alternative Approaches

Research at the Lawrence Berkeley National Laboratory (Seol et al., 2006) describes the inherent difficulty of performing traditional relative permeability measurements of gas and water in the presence of hydrates. One of the goals of Seol et al. was to limit the formation of

additional hydrates during flow experiments. In order to estimate relative permeability properties, they performed an experiment by which hydrates were formed in a sandstone sample and permeabilities of gas and water were measured independently. Using X-ray computed tomography (CT), they estimated the saturations of hydrate, gas, and water in real time. By analyzing the permeability characteristics of each phase in real time, the researchers were able to estimate relative permeability by inverse modeling with TOUGH/iTOUGH2, a software program developed for simulating various hydrate behaviors.

2.4 Methods for Determining Absolute Permeability

Permeability is one of the fundamental properties of a reservoir rock. There are various ways to measure permeability, one of which is to flood the core with a fluid and calculate permeability using Darcy's equation. Although this is a good method of measuring permeability, it is time-consuming and requires cutting core plugs of specific dimensions for flooding.

Another method of permeability measurement is using probe permeameters. Probe permeameters are pressure-decay devices that can perform fast, non-destructive permeability measurements. Probe permeameters work on the principle of flow through porous media as empirically defined by Darcy's law.

Probe permeameters work by applying pressure on the rock surface with the help of a probe tip such that only the gas that is used to pressurize (usually air or nitrogen) the sample can dissipate through it. Once stable pressure is achieved at the probe (flow equilibrium), a calibrated volume of gas at that pressure is locked in by a valve. This results in pressure decline as the gas dissipates through the rock. Probe permeameters use the rate of this pressure decline to determine the permeability of the sample.

Chapter 3

This chapter details setups and procedures for both relative permeability experiments and absolute permeability experiments, performed as part of this study. The first section is devoted to relative permeability measurements, and the second, to absolute permeability measurements.

3.1 Relative Permeability Experiments

The initial experimental apparatus used for determining relative permeability was designed and assembled at the University of Alaska Fairbanks. The setup had two main purposes: (1) to form hydrates and preserve them and (2) to perform relative permeability experiments. A detailed explanation of the experimental setup at UAF's labs is given in the sections that follow. The primary difference between work performed at UAF and work performed at ConocoPhillips labs is the use of a magnetic resonance imager (MRI) at ConocoPhillips. Other components used at ConocoPhillips labs are not explained in detail. The equipment, however, is equivalent and often superior in capability to that used at UAF.

3.1.1 Experimental Setup

The experimental setup consisted of components commonly found in experiments typical to the petroleum industry and those involved in lab research.

3.1.1.1 Core Holder

The core holder used in this experiment could accommodate cores of 2 in. in diameter and up to 12 in. long. Cores were held in a rubber sleeve around which overburden pressure would be applied. In this experiment, the surrounding volume was filled with tap water and then pressurized with high-pressure helium up to 1700 psi. The core holder maintained a specific temperature (specified by the user) with the use of a cooling jacket connected to a refrigeration unit. The refrigeration unit that was used to maintain the core holder temperature was a Julabo FP50 model; it was controlled via the data-logging Dell computer. The cooling system could be set to a specific temperature or could be set to heat or cool at a given rate. The coolant used was a mixture of 50% propylene glycol and 50% water.

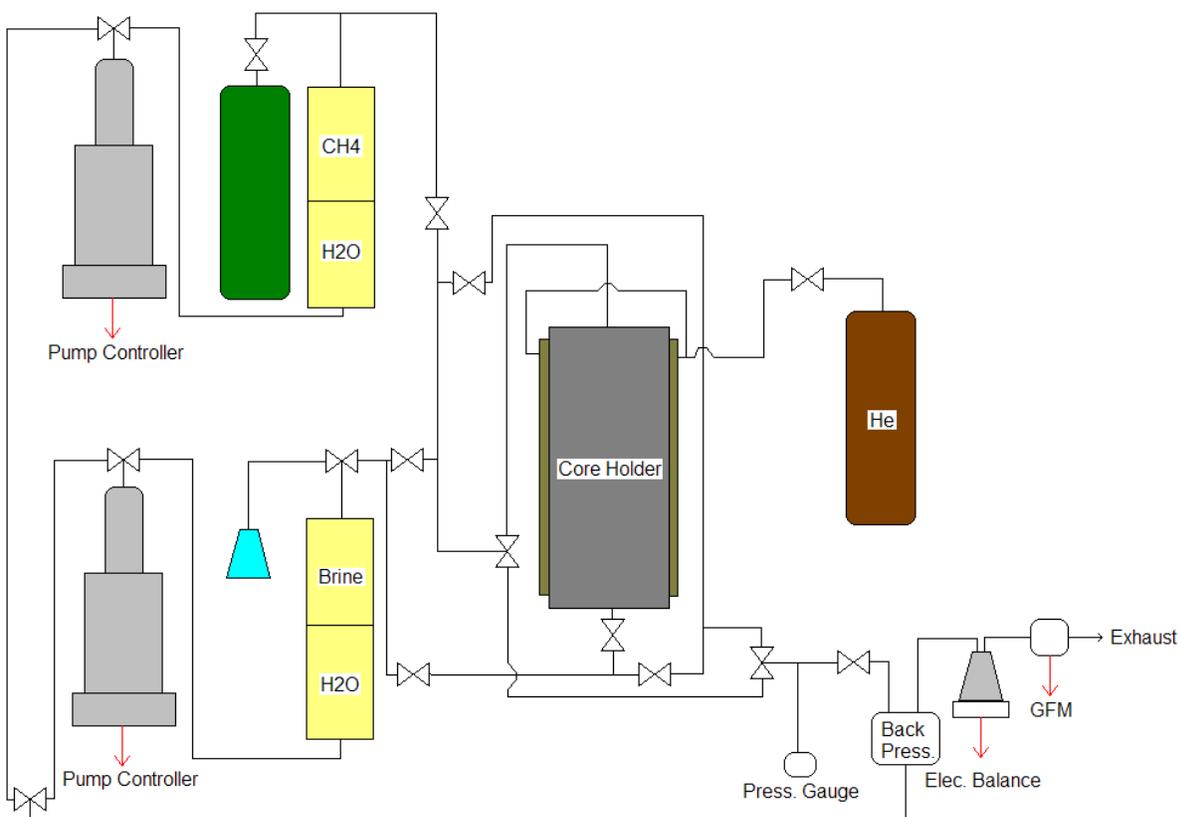


Figure 3.1: Experimental setup.

3.1.1.2 Injection System

Two Isco Series D pump controllers connected to Isco 500D syringe pumps controlled the flow of methane and brine in the experimental setup. Di-ionized water was used in the pumps to assure that proper functions were maintained. Water that the pumps injected was used to move a piston in either one of two accumulators that would inject an equivalent amount of brine or methane at the same pressure.

The pumps injected fluids at either constant flow rates or constant pressure. When performing absolute water permeability experiments using cores with lower permeabilities (<50 mD) and during hydrate formation, it was found that constant pressure injection was preferred to constant rate. When using cores with higher permeabilities and during displacement experiments, it was

found that a constant rate worked best. The pumps were run anywhere from 10 to 1500 psi, with flow rates typically from 0.010 mL/min up to 5 mL/min.

Both the gas and brine accumulators were wrapped with copper tubing, which was connected to a NESLAB Endocal RTE-4 refrigeration unit that operated independently of the Julabo unit. Its purpose was to pre-cool the fluids during flow experiments when hydrates were present in the core holder. This was done to avoid any unwanted hydrate dissociation due to the injection of warmer fluids above the hydrate stability temperature.

3.1.1.3 Production System

In order to conduct flow experiments, it became necessary to maintain a certain backpressure and monitor the rate and composition of produced fluids. Therefore, a subunit consisting of three components—a back pressure regulator, a gas flowmeter, and electronic balance—was assembled.

The backpressure regulator used was a Temco BP Series, rated to 5000 psi. It operated by applying fluid on the dome side of a Teflon diaphragm, which acted as a closed valve when the moving fluids (brine and methane) were below dome pressure. When the pressure of the moving fluid was above dome pressure, the diaphragm would allow flow, thereby lowering the pressure back towards the set point. When functioning properly, the regulator maintains its set pressure and allows flow accordingly.

At times, it was seen that using a gas source for applying dome pressure was sufficient. However, experience showed that pressure applied to the dome side did not always translate into flowing backpressures of the same value. Small amounts of contamination from fines migration, mechanical stress on the diaphragm, and/or other undetermined issues caused irregular backpressure operation. The use of ISCO pumps to control backpressure made the small and large adjustments of the backpressure (and therefore the flow of downstream fluids) much easier as compared with a high-pressure nitrogen cylinder operated with a choke and no bleed valve. This arrangement was especially important during flow through a hydrate-saturated sample when maintaining overall pore pressure was critical for hydrate stability. It was seen that sometimes

dome pressure would be in error by 100–200 psi when compared with actually flowing pressure. However, if the appropriate backpressure could be quickly achieved, this discrepancy was ignored.

The gas flowmeter used was an Aalborg GFM17 model. It was capable of measuring flow between 0 L and 2 L per minute. Data was recorded every second to increase measurement accuracy. Unlike other components of the setup, such as the pump or the electronic balance, true volume could not be measured. Only flow at given time steps could be measured. Therefore, to reduce the transient error inherent to the system, data was taken every 1 sec, as opposed to 5 sec to 1 min for other devices.

The mass balance was used to weigh the brine that was removed from the system. In the flow diagram, it was placed upstream of the backpressure regulator and downstream from the gas flowmeter. An enclosed metal accumulator was placed on an AND GF-4000 electronic balance, and the weight was tared. Therefore, any brine produced subsequently would be observed as an increase in the weight of the total setup.

3.1.1.4 Data Collection

Data was recorded by two main devices during the course of an experiment. The first device was the injection pump of interest. Pumps logged the flow rate, pressure, and cylinder volume. The second device was on the downstream side for recording the gas flow rate and the time-dependent balance measurement. When hydrates were actively recorded, temperatures of the core holder were measured. Temperatures were monitored during the entire experiment, although only recorded during hydrate formation. Data that was taken with different logging software was often set to record values at identical timesteps so that data could be easily analyzed at a later period with Microsoft Excel and other software programs. For absolute and effective permeability experiments, data was commonly taken every five seconds. Hydrate formation was a much slower process, and therefore one-half of a minute was selected as an appropriate time interval.

3.1.1.5 Magnetic Resonance Imager

The solicitation of ConocoPhillips for work on this project stemmed from its ability to monitor water saturations in core samples before, during, and after hydrate formation. The MRI model used in this experiment was a Varian 2 Tesla Superconducting Magnet (see Figure 3.2) with a 7 Gauss/cm gradient. It has the ability to take measurements every cubic millimeter and can take a 3-dimensional image with dimensions of 32 x 32 x 128 mm.

Commonly only 1-dimensional profiles were taken due to their speed of acquisition, which was normally between 15 seconds to 1 minute. Two- and three-dimensional images inherently took longer (approximately one-half hour to four hours) and therefore were not practical during transient testing periods, except for with hydrate formation, which has a much slower reaction.

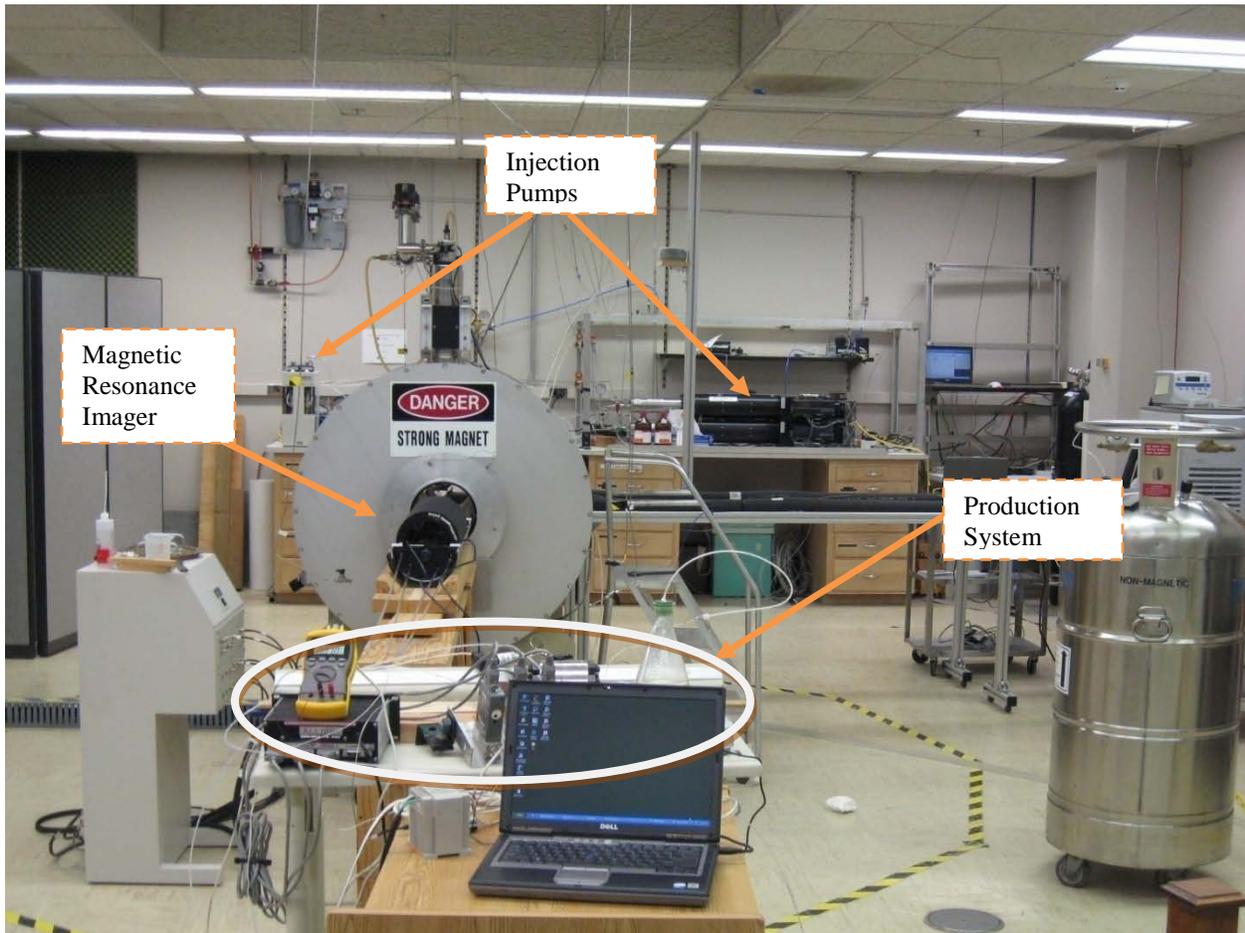


Figure 3.2: MRI setup.

3.1.2 Experimental Procedure

The following sections detail how the relative permeability experiments in the presence of gas hydrates were performed. These experiments utilized unconsolidated core samples taken from the Mt. Elbert exploratory well drilled on the Alaska North Slope in February 2007. Other sandstone cores were used to become comfortable with the experimental setup and to fine-tune experimental procedures.

3.1.2.1 Initial Core Saturation

The first step of the experiment was to saturate the core samples with 100% water and establish base permeability. If the core was known to contain small amounts of water (either when beginning with a new core sample or after certain previous experiments), water was injected at a constant rate until continuity was observed in the sample. If a continuous phase of water was not present, maintaining pumps at constant rate would be difficult due to the compressibility of air and the incompressibility of water. When beginning with a relatively dry sample, running the pumps at constant pressure could have caused the pump to run at high flow rates, which could exacerbate fines migration, break filters at the core plug ends, or both. Broken filters most often led to fines entering the experimental tubing, clogging them and causing component replacements. Sometimes this also led to sand collecting in the backpressure regulator, causing erratic behavior. Once it was determined that the core was mostly saturated, the pump and the backpressure regulator were set at constant pressure, and the flow rate of the pump was logged. Constant flow rate and pressure over time indicates steady-state flow. Absolute permeability was then calculated using Darcy's law.

3.1.2.2 Hydrate Formation

After determining absolute permeability, hydrate formation was started. The initial step called for the evacuation of some water and injection of methane into the core sample. This was done in one of two ways. The first method was by bringing water and gas into contact with each other at the desired pressure for hydrate formation. Then, setting the brine pump to refill mode and the gas pump to injection mode—both at the same flow rate—water was removed and gas injected. The second method was essentially to open the bottom of the core holder to the

backpressure regulator and allow gas to displace water out of the core. This was done when it was desired that larger amounts of water be removed. When gas was seen at the core outlet and the predetermined amount of water was collected, the injection was halted.

The gas pump then was able to maintain pore pressure in the core. The downstream side of the core holder was shut in, and the gas pump was set to constant pressure. The refrigeration unit connected to the core holder was cooled to the point desired for hydrate formation. At UAF, the temperature was brought to operating temperature from room temperature over the course of about 4 hr. The refrigeration set temperature and the core temperature were not the same value, as there were heat transfer losses in the system between the refrigerator and the core holder. Therefore, thermocouples were used to log the temperature and confirm that experiments were being conducted at the proper temperature. At ConocoPhillips, the practice was to merely set the temperature for the desired end temperature and cool the core as fast as possible. In analyzing both methods, both appear to form hydrates just as easily. This subtle nuance was not considered critical to the overall project and, therefore, was not explored in greater detail. Both were considered valid approaches.

As the core cooled, hydrate formation caused the consumption of methane gas, which, without running the pump at constant pressure, would lead to a drop in pressure. During peak initial hydrate formation, a noticeable spike in flow rate (and therefore pump cylinder volume) was observed. In all cases, this indicated good hydrate formation. Hydrate formation was typically done overnight, and the duration of this experiment was approximately 12 to 15 hours. Hydrate formation usually occurred over the first few hours, when the temperature and pressure were within the hydrate equilibrium region. After an hour or two, the pump flow rate was not observed to flow at an appreciable rate. Extended duration of this step, theoretically, could have led to more hydrate formation, but would have probably led to less permeability.

3.1.2.3 Permeability Determination with Hydrates

Procedures for determining permeability in the presence of hydrates consisted of re-saturating the remaining pore volume with water and then displacing it with gas. Water was

re-saturated to ensure uniform distribution of one of the phases prior to beginning the relative permeability experiment.

Saturation with water was conducted in the same fashion as absolute permeability. The injection pump was set to constant pressure with constant backpressure. Steady flow through the core sample at equalized pressure then allowed for the calculation of permeability using Darcy's law.

Following saturation, the procedure was to inject gas at a constant rate beginning at the initial pore pressure of the core sample. Injection rates, rate of production of each fluid, and pressure drop were monitored. The experiment was complete when irreducible saturation of the brine phase was achieved. Relative permeability was then calculated using the JBN method (Johnson et al., 1959).

3.2 Absolute Permeability Experiments

3.2.1 Experimental Setup

For this study, a lab-based probe permeameter—Core Lab UPP-200—was used (Figure 3.3). To test the applicability of this permeameter in measuring the permeability of frozen core samples from well MEO1, a feasibility study was carried out before the actual measurements.

During this phase of the study, the probe permeameter was set up at the ASRC core storage in Anchorage, Alaska. A small set of core samples from the known hydrate-bearing section of the well were selected and carefully measured to obtain permeability data. This data was logged and compared to the values obtained previously during routine core analysis by OMNI Labs.

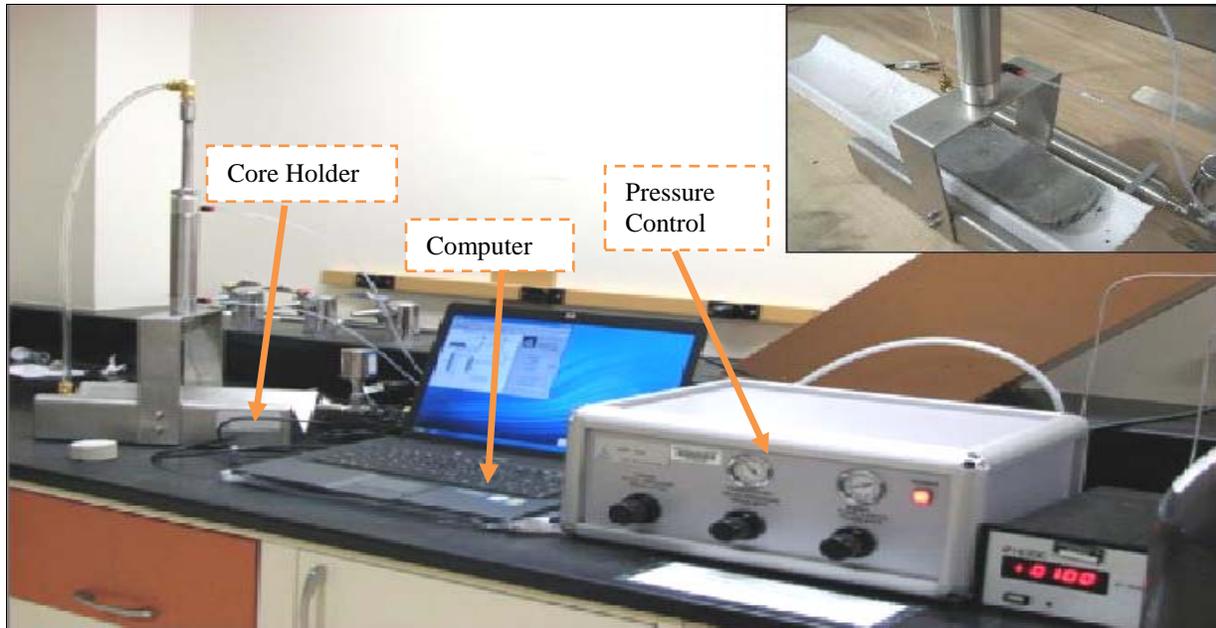


Figure 3.3: Core Lab UPP-200 probe permeameter. (Inset: Core holder with Mt. Elbert core during the feasibility study.)

The following observations were made during the feasibility study:

- A good match was observed between the permeability data obtained using the probe permeameter and the data obtained by OMNI labs.
- The probe permeameter and the related equipment worked well in low temperature conditions maintained in the refrigerated core storage.
- To accommodate the core samples in the core holder, the samples were moved out of the core box and placed in the core holder to take measurements. This proved to be destructive for the core samples and slowed down the measurement process.
- The V-shaped core holder of the UPP-200 (Figure 3.3, Inset) did not provide adequate support for the cores and increased the risk of core damage.

Based on the above observations, it was concluded that the most effective and safe method for measuring permeability would be to measure it without moving the cores from the core box. This method would greatly reduce the risk of core damage due to transferring, and a core box would provide good support to the cores during measurement. Thus, a new core holder was designed (Figure 3.4) that could accommodate the standard core box (37½ in. x 12¾ in.). This core holder

was then fabricated locally (Figure 3.5) and used to perform the permeability measurements. It proved to be very effective in reducing both damage to the cores and time spent measuring permeability.

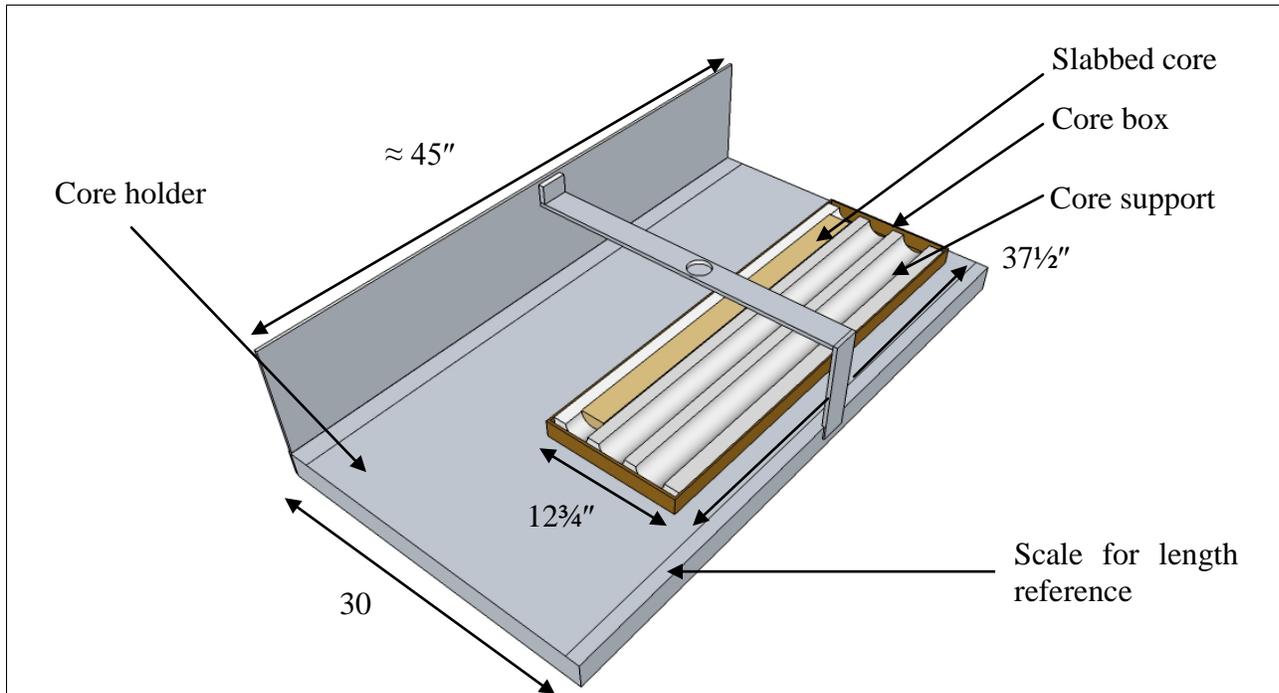


Figure 3.4: New core holder designed for Mt. Elbert permeability study (not to scale).

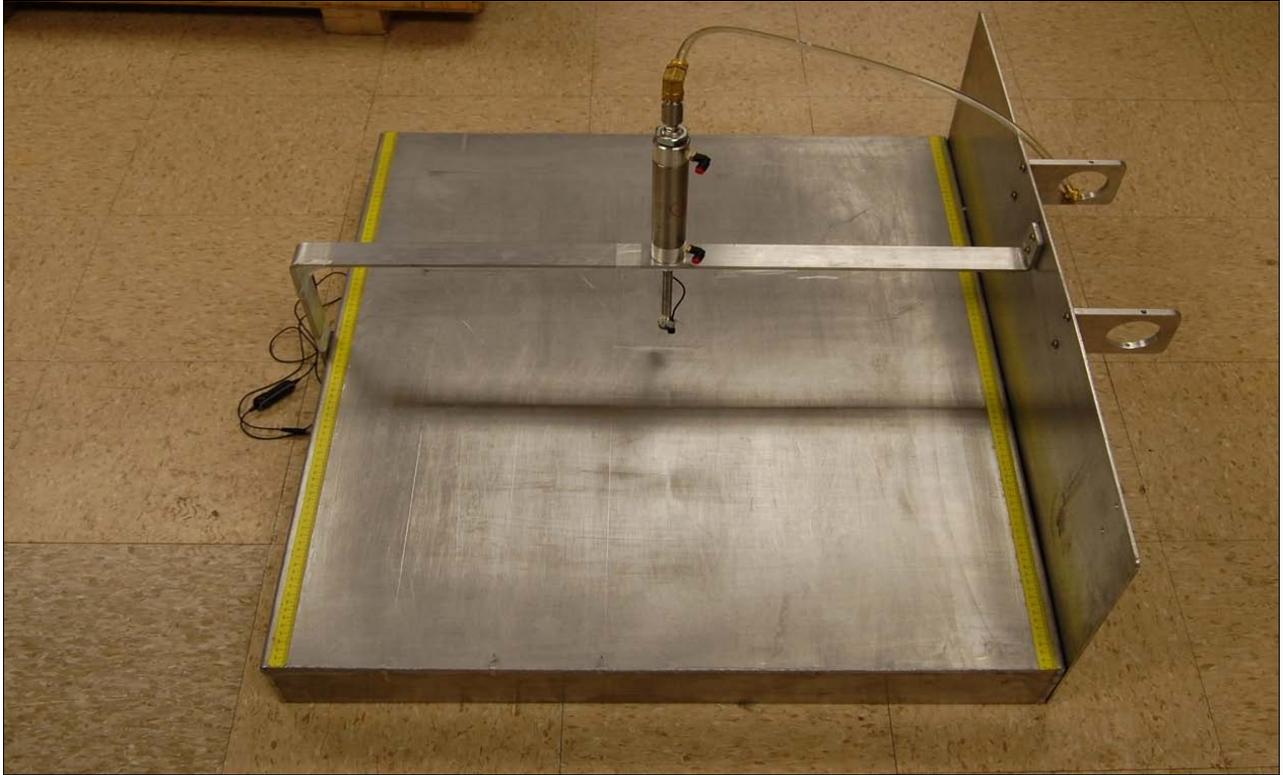


Figure 3.5: New core holder for Core Lab UPP-200.

3.2.2 Experimental Procedure

After the modified probe permeameter setup was fabricated and tested, it was transported to the ASRC facility in Anchorage, Alaska, to perform permeability measurements on the available core from Mt. Elbert well ME-01. The permeameter was set up inside the refrigerated core storage unit to measure the cores without risk of their thawing. Care was taken to maintain the temperature in the unit below 40°F.

A total of 400 ft of core samples from Mt. Elbert well ME-01 were measured. Permeability data logged by the probe permeameter were also logged manually as a backup, and remarks were made about the condition of the core samples. Places at which permeability measurements were performed were marked and photographed for future reference (Figure 3.6).

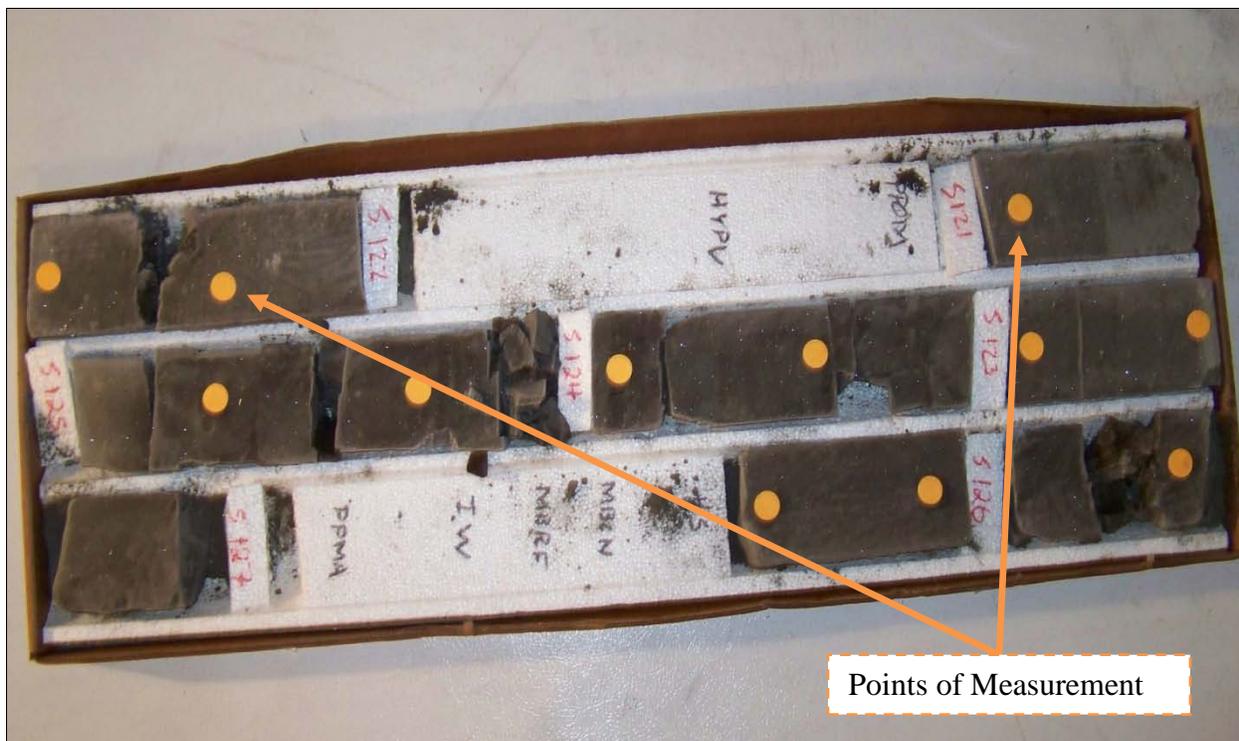


Figure 3.6: A core box with core samples showing points of measurement.

Chapter 4

Results of work completed for this study are compiled in this chapter. As with the previous chapter, relative permeability and absolute permeability experiments are separated into two sections along with their respective results and discussion. Relative permeability experiments were conducted using the unsteady-state displacement method in the presence of reformed methane hydrates. Absolute permeability of frozen Mt. Elbert cores was determined with a probe permeameter.

4.1 Relative Permeability

4.1.1 Results

The first part of this project was to determine the gas-brine relative permeability characteristics of representative methane hydrate-saturated core samples. The goal was to form hydrates over a range of saturation that still permitted two-phase flow.

To date, relative permeability in the presence of hydrates has not been determined for Mt. Elbert core samples. The presence of hydrates inevitably leads to reduction in permeability of porous media. At times, the presence of hydrates has manifested itself as reducing permeability to a level that is immeasurable, or where permeability of water can be determined but not that of gas. The following sections highlight certain experimental results and discuss issues encountered during each phase.

4.1.1.1 Absolute Permeability

Determining absolute permeability during each iteration of the experiment was least problematic. Even though Mt. Elbert cores have low permeability and higher than insignificant clay content, steady-state flow was achieved in nearly every iteration with permeability determined by Darcy's law. Figure 4.1 is an example of the type of data recorded during this step. This test was conducted at constant differential pressure. From the figure, it can be seen that flow rate reached steady state over the course of the experiment. The permeability corresponding to this particular test was 1.04 mD.

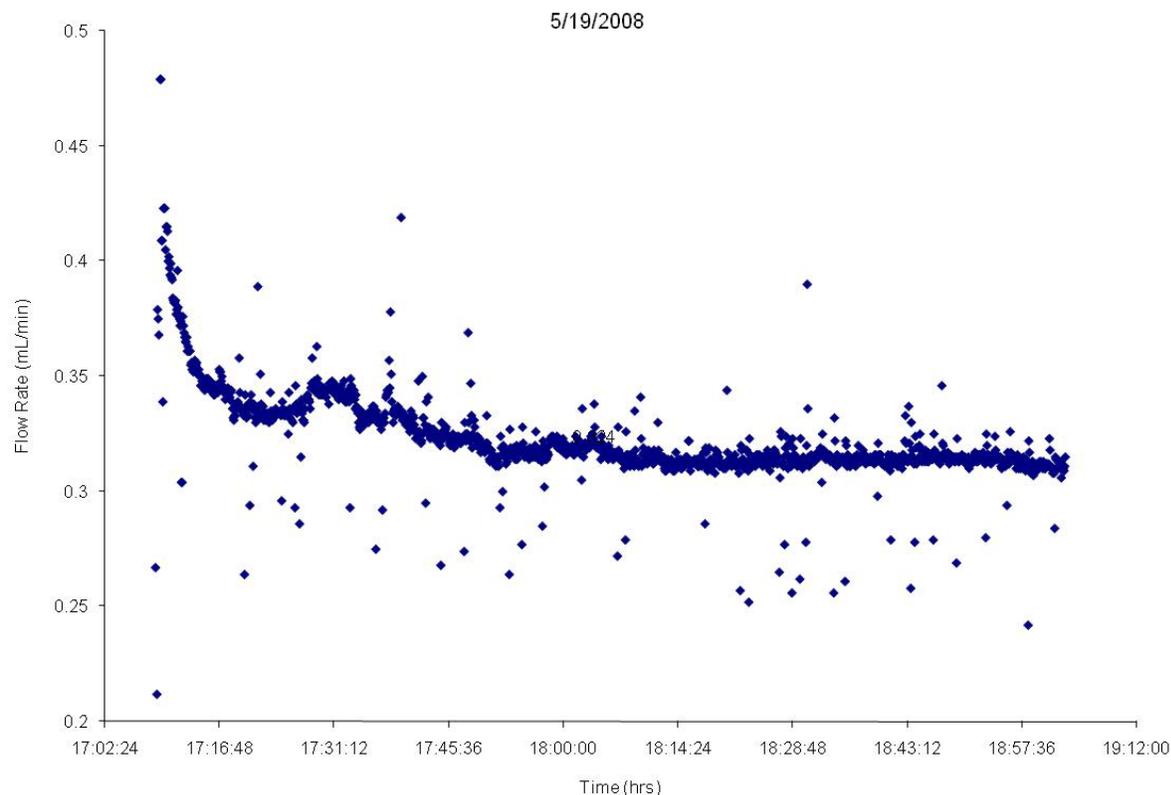


Figure 4.1: Absolute permeability example.

4.1.1.2 Hydrate Formation

As mentioned in previous sections, the formation of methane hydrates depends on many factors. Key in determining the quantity of hydrate formation is the relative availability of each of the constitutive components: water and methane. When gas pressure is supported by the gas pump, water is the limiting component for hydrate formation. Over many trials, it was often quite difficult to remove significant enough water from the core samples to form low saturations of hydrates (<20%).

Use of the MRI showed that water saturation could be reduced from approximately 50% to nearly zero in the presence of excess gas. The before-and-after pictures shown in Figures 4.2 and 4.3 give an indication of the level of free water reduction. Green colors indicate the presence of free water. No signal indicates the presence of either gas or hydrate. Blue colors indicate noise, which could not be completely filtered out.

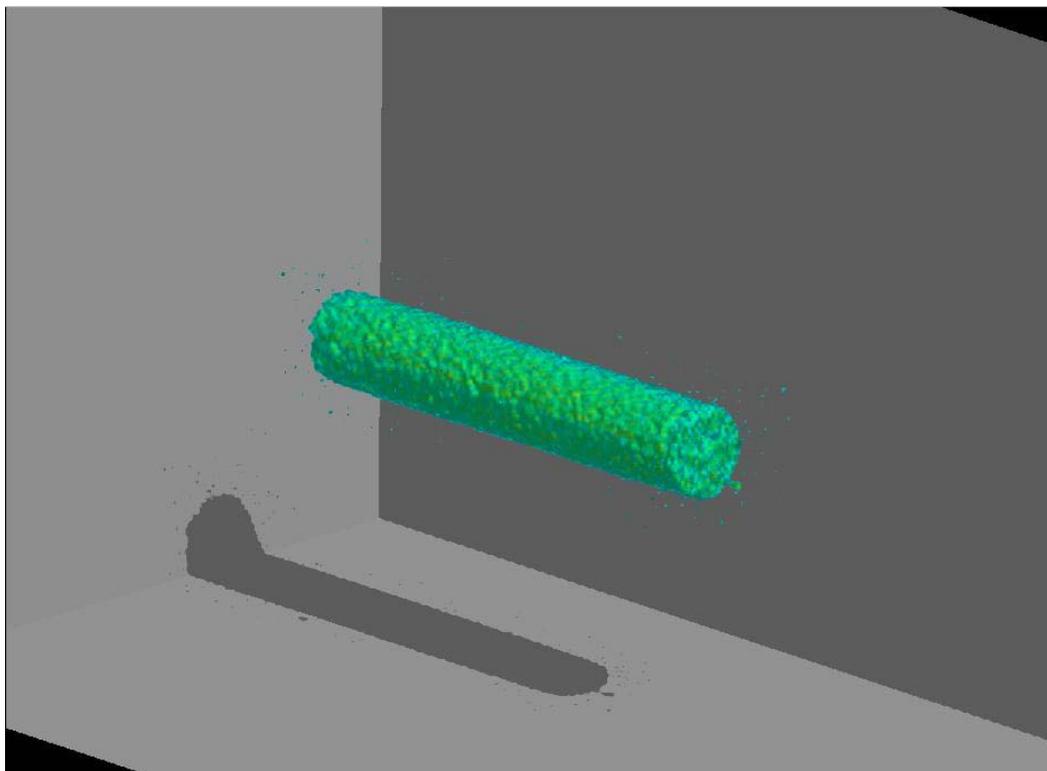


Figure 4.2: Initial saturation of gas and water prior to hydrate formation.

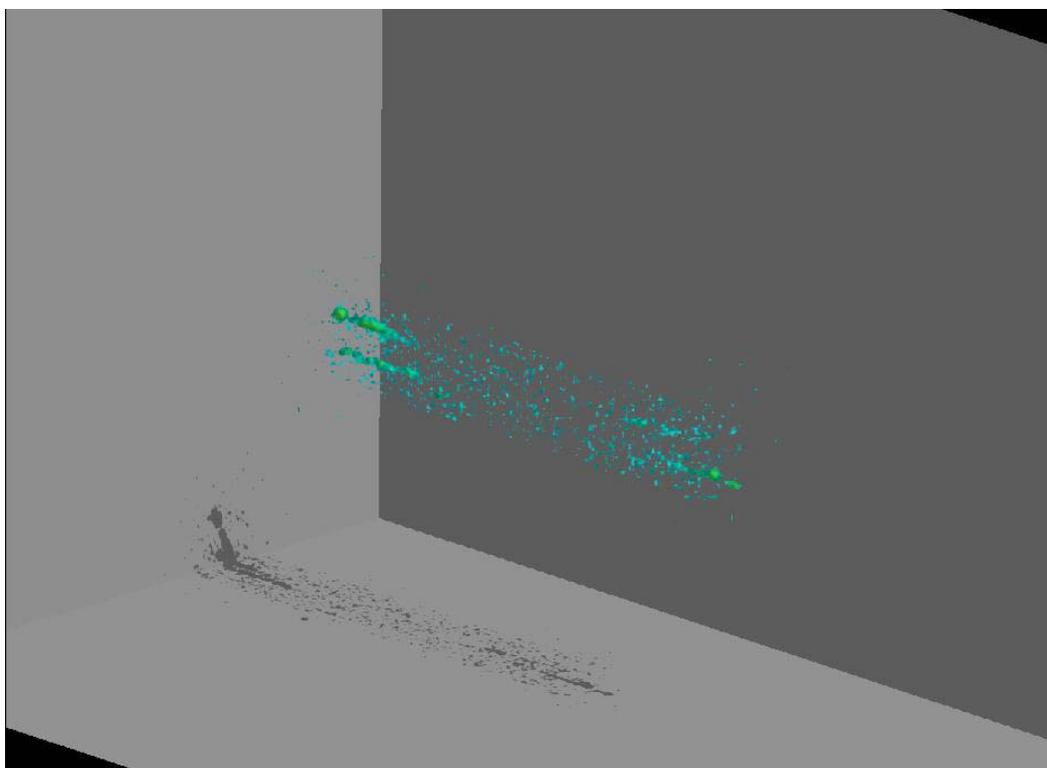


Figure 4.3: Sample with formed hydrates.

Without the use of an MRI, hydrate formation is inferred by analyzing data from the methane injection pump. At constant pressure and with no active formation of hydrates, the flow rate is observed to be nearly zero. When hydrates form, the pressure is supported by active injection by the pump. A large spike is indicative of hydrate formation accompanied by a drop in pump cylinder volume. Figure 4.4 is a good example of this behavior.

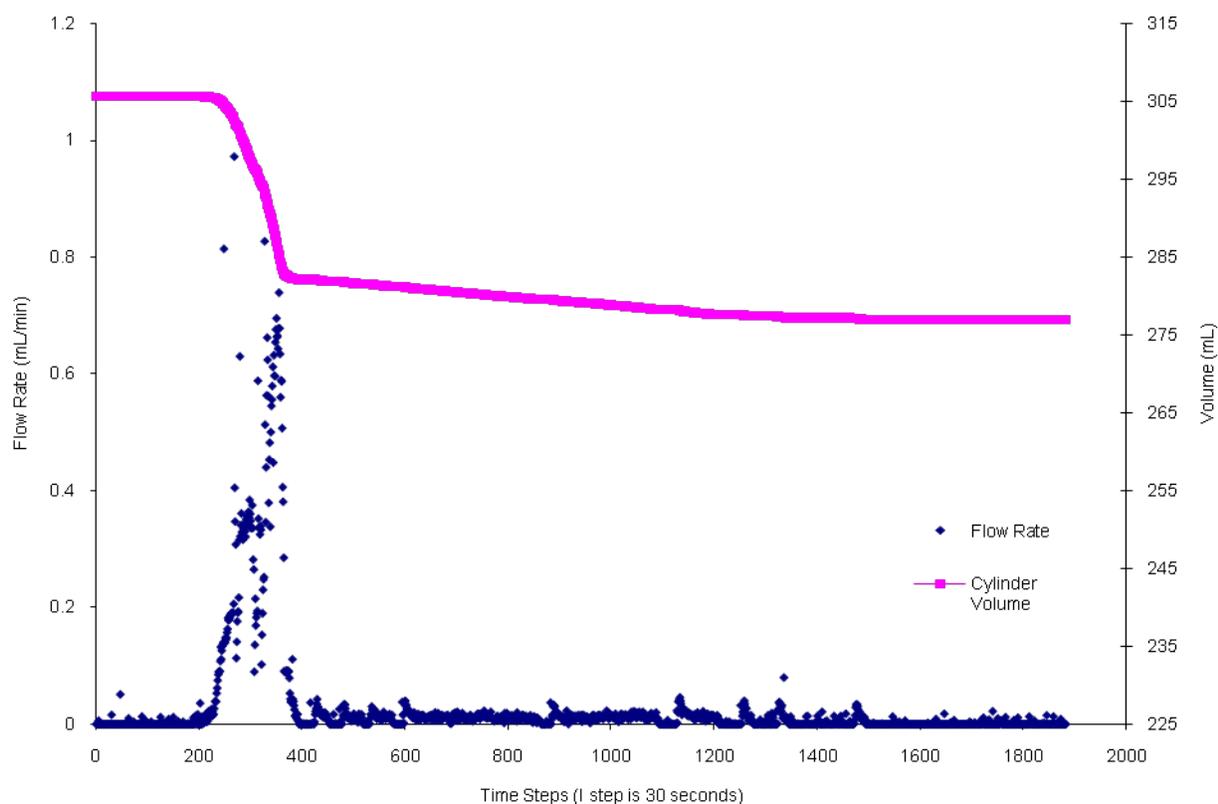


Figure 4.4: Hydrate formation example.

4.1.1.3 Effective Permeability

Following hydrate formation, it was common practice to re-saturate the remaining pore volume with brine, which also served to determine the maximum effective permeability of water in the presence of hydrates without excess gas. Figure 4.5 is a good example of this phase of the experiment. The effective permeability associated with this flow test was 0.24 mD.

There were many instances when achieving this data set was quite difficult. When hydrates either formed too completely (high saturation) or locally around the water injection point, no measurable permeability was obtained, and that particular test was abandoned.

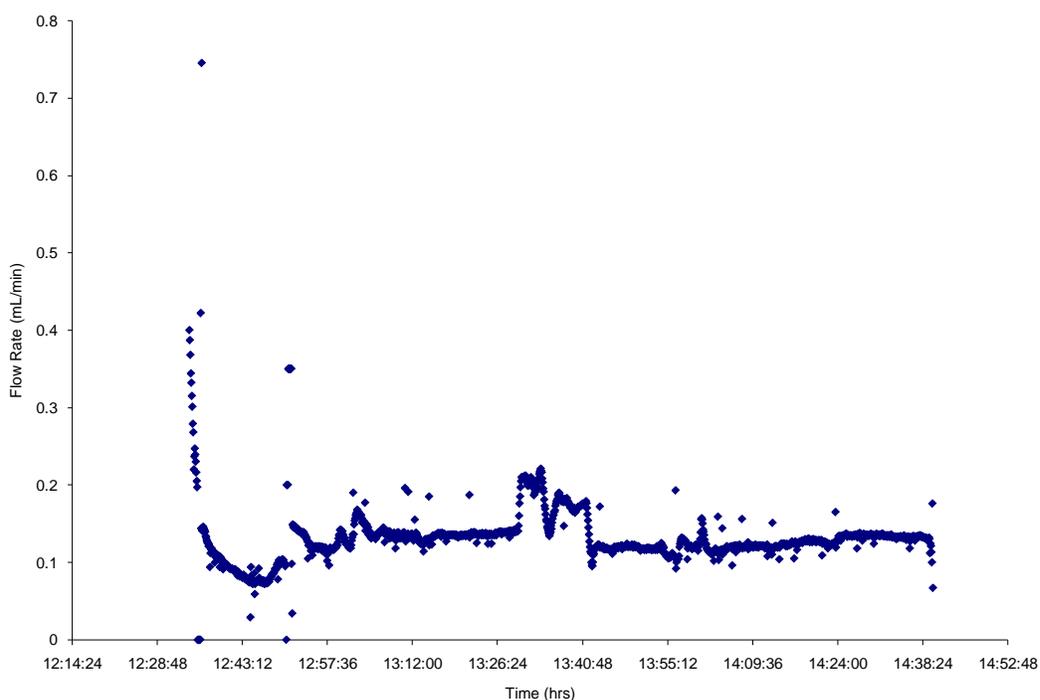


Figure 4.5: Effective permeability example.

4.1.1.4 Displacement: Relative Permeability

Relative permeability measurements, one of the main goals of this study, have been the most difficult to achieve. This has been due to factors known, theorized, and still unknown. What is clear is that permeability of gas in hydrates reformed in Mt. Elbert core samples is a key factor in this difficulty.

When injecting gas to displace water in the presence of hydrates, it has been observed on numerous occasions that in the initial stages of the experiment the permeability has been reduced to immeasurable amounts when attempting to displace water with gas. Two theories about this

phenomenon suggest (1) additional hydrate formation at the interface between brine and gas, and (2) high capillary pressure that restricts the flow of gas and then subsequently leads to hydrate formation.

Work with a sandstone core that was imaged with the MRI late during this research has indicated that, given high enough permeability, additional hydrate formation or the effects of high capillary pressure during this phase can be either mitigated or drastically reduced. During this one trial, water saturation before hydrate formation was reduced beyond what was possible just by gas displacement, resulting in low hydrate saturation in a highly permeable core sample.

Following hydrate formation, both effective permeability measurements and a displacement experiment were conducted. During initial flooding and the subsequent displacement experiment, it was observed that two-phase flow with gas and brine did not occur, indicating that unsteady-state experiments with gas and brine are possibly not feasible. Figure 4.6 is a qualitative analysis of the flow brine and gas, both injected and accumulated.

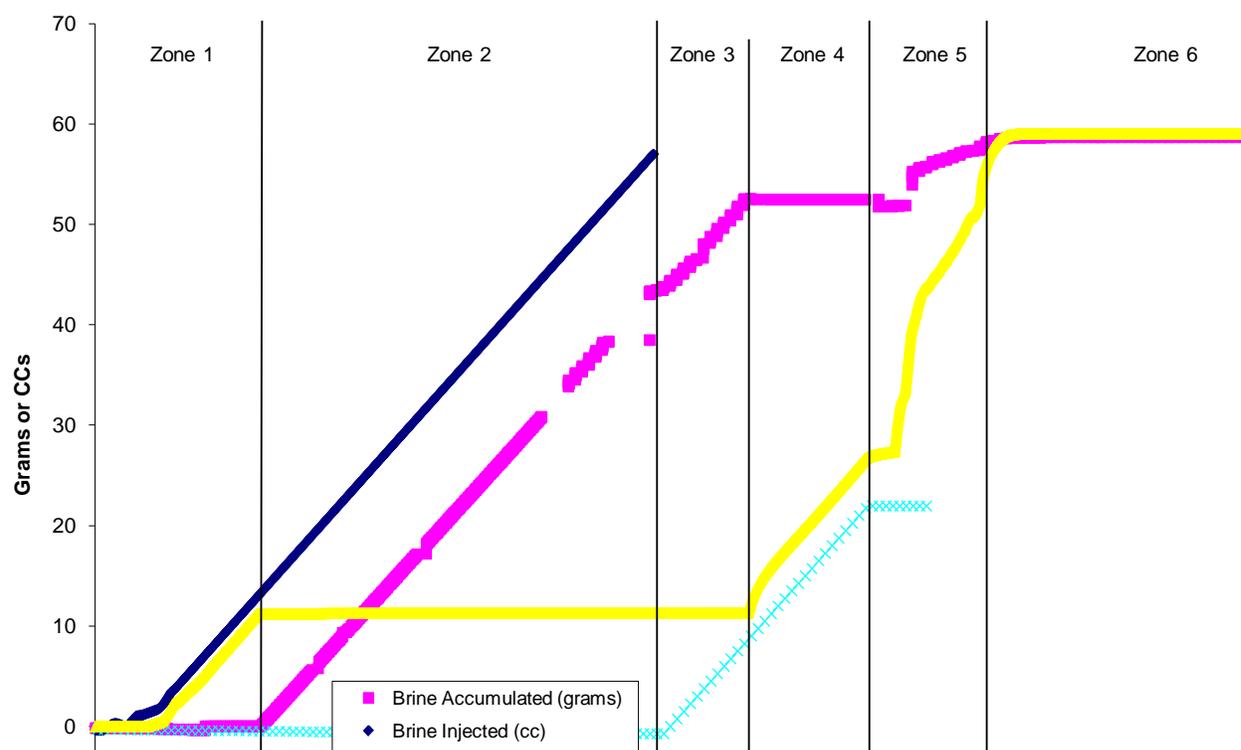


Figure 4.6: Flow analysis during effective and relative permeability experiments in the sandstone sample.

Figure 4.6 shows some of the inherent problems of unsteady-state displacement with brine and gas. As either brine or gas is injected (for brine in Zones 1 and 2; for gas in Zones 3 and 4), the other phase, which is known to be nearly 100% saturated, is displaced at a rate relatively equal to that of the injected phase. This occurs until the injected phase reaches the end of the sample. Then, essentially, effective permeability at the other phase's zero, or reduced, saturation is observed. For JBN analysis to be used following unsteady-state experiments, there must be appreciable flow of both phases over a range of saturations.

4.1.2 Discussion

It is the opinion of the authors that one of the key difficulties with this experiment was the use of unconsolidated samples. While Jaiswal (2004) reported success using sandstone core with a similar setup and procedure, the authors of the present work believe that further validation of those results is needed before trying to conduct the same experiment with unconsolidated cores.

By their nature, hydrates are an immobile phase present within the pore spaces of either unconsolidated sediment or another porous media; therefore, they inhibit permeability for other phases present within the same media. Using different core handling techniques, which range from compacting sediments to maintaining bulk dimensions and porosities, it was found that Mt. Elbert cores had severely limited permeability both with and without hydrates present. Neither procedure seemed preferable; both have their own inherent difficulties. Compacting sand from core samples reduced porosity and permeability. Maintaining bulk dimensions made the application of overburden pressure which is necessary for forming hydrates a painstakingly slow process.

Flowing one or more fluids (methane and brine) through a core sample in the presence of hydrates was extremely difficult and sometimes, as mentioned before, was not at all successful. This report's authors believe that using consolidated sandstone cores with much higher native permeability would help to simplify many of the experimental considerations. Work at ConocoPhillips' Bartlesville Technology Center validated that both brine and methane could be injected through a sandstone core sample containing hydrates. With Mt. Elbert cores, this has not been achieved once. This single experiment still used the unsteady-state displacement method in order to determine relative permeability. Due to apparent piston-like displacement of gas by water and apparent fingering of gas through water, two-phase flow, which is necessary in using the JBN method, was never observed. However, these promising results confirmed that both phases can be injected through a hydrate-bearing sample without significant additional hydrate formation if there exists significant enough permeability. The authors believes that employing a steady-state relative permeability experiment using a sandstone core with low hydrate saturations offers the best possibility for success at present.

It is possible that traditional laboratory measurements for determining relative permeability in hydrate samples may not be viable. Hydrates in this experiment were formed over short durations—only hours. It is not known how long it takes hydrates to form in nature, but theoretically, it could take untold years. Therefore, it is not easy to determine if the hydrate distribution in these core samples is representative or not. It is our opinion that the higher the saturation of hydrates, the lower the degree of uncertainty with respect to these considerations.

That is to say, the greater the hydrate saturation, the less deviation there is from equivalent hydrate saturations in nature.

4.2 Absolute Permeability

4.2.1 Results

The absolute permeability of Mt. Elbert core samples that do not contain hydrates was determined in order to compare it with data measured by Omni Labs. The following tables are a comparison of permeability values measured using UPP-200 with those measured by Omni Labs (Table 4.1) and a comparison of measured permeability and percent change in permeability with depth (Table 4.2).

Table 4.1: Comparison of measured permeability values.

Sample Mid Depth (ft)	Permeability to Air (mD) Omni	Permeability to Air (mD) UAF (Nearest Reading)	Actual Depth for the UAF Reading
1997.435	0.155	26.4	1997.83
2017.1	12.2	62	2017.46
2045.9	1370	723	2046.21
2051.45	1630	567	2050.88
2106.085	0.069	53.5	2106.88
2124.75	145	15.2	2124.54
2163.4	675	2.65	2163.5
2180.25	7650	2152	2180.04
2224.15	1.01	14.5	2224.71
2225.415	0.0031	8.9	2225.79
2274.7	2.68	353	2274.29
2301.1	815	186	2301.29
2396.335	0.039	8.01	2396.79
2454.95	1.34	1.28	2454.88
2470.6	0.887	0.381	2470.79
2482.15	0.77	1.96	2482.38

Table 4.2: Comparison of measured permeability values with percent change along depth.

Sample Mid Depth (ft)	Permeability to Air (mD) Omni	Permeability to Air (mD) UAF (Nearest Reading)	Actual Depth for the UAF Reading	% Change in Permeability Along Depth, OMNI	% Change in Permeability Along Depth, UAF
1997.435	0.155	26.4	1997.83		
2017.1	12.2	62	2017.46	7770.967742	134.8484848
2045.9	1370	723	2046.21	11129.5082	1066.129032
2051.45	1630	567	2050.88	18.97810219	-21.57676349
2106.085	0.069	53.5	2106.88	-99.99576687	-90.5643739
2124.75	145	15.2	2124.54	210044.9275	-71.58878505
2163.4	675	2.65	2163.5	365.5172414	-82.56578947
2180.25	7650	2152	2180.04	1033.333333	81107.54717
2224.15	1.01	14.5	2224.71	-99.98679739	-99.32620818
2225.415	0.0031	8.9	2225.79	-99.69306931	-38.62068966
2274.7	2.68	353	2274.29	86351.6129	3866.292135
2301.1	815	186	2301.29	30310.44776	-47.30878187
2396.335	0.039	8.01	2396.79	-99.99521472	-95.69354839
2454.95	1.34	1.28	2454.88	3335.897436	-84.01997503
2470.6	0.887	0.381	2470.79	-33.80597015	-70.234375
2482.15	0.77	1.96	2482.38	-13.19052988	414.4356955

4.2.2 Discussion

Comparison of permeability values measured with the probe permeameter show a wide variability similar to the variability shown by the OMNI readings. This is indicated by a similar percent change in permeability along depth in both the probe permeameter and OMNI readings (highlighted in red in Table 4.2). The probe permeameter values show good correlation in the lower range of the permeability readings with the OMNI values.

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