Arnold Schwarzenegger
Governor

PHYSICAL MODELING OF CO_2 SEQUESTRATION

PIER FINAL PROJECT REPORT

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Prepared By:
Roland N. Horne
Stanford University

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Prepared By:
Stanford University
Roland N. Horne
Department of Energy Resources Engineering
367 Panama Street
Stanford, CA 94305-2220
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Prepared For:
Public Interest Energy Research (PIER) Program
California Energy Commission

Gina Barkalow
Project Manager

Beth Chambers
Contract Manager

Kelly Birkinshaw
Program Area Lead
Energy-Related Environmental Research

Laurie Ten Hope
Office Manager
Energy Systems Research

Martha Krebs
Deputy Director
ENERGY RESEARCH & DEVELOPMENT DIVISION

B.B. Blevins
Executive Director

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Physical Modeling of CO_2 Sequestration is the final report for the Physical Modeling of CO_2 Sequestration project (CIEE award number MEX-06-09, WA number MR-043, under CEC/CIEE prime contract number 500-02-004) conducted by Stanford University. The information from this project contributes to PIER's Energy-Related Environmental Research Program.
For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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1.0 Abstract

With the increasing concern about global warming, many technologies have been developed to help mitigate carbon dioxide (CO_2) emissions to the atmosphere. The primary motivation for this research has been to investigate the mitigation technology of sequestering the CO_2 in deep geological formations, particularly saline aquifers. The displacement of water by CO_2 is critically dependent on the physical property known as relative permeability. By measuring the relative permeability of CO_2 gas and water in an experimental apparatus, we were able to determine that the phenomena of CO_2 solution and dissolution have very significant effect on the displacement of CO_2 gas into water.

2.0 Executive Summary

In a series of experimental measurements, we have found that the phenomena of CO_2 solution and dissolution have very significant effect on the displacement of CO_2 gas into water. The implications on CO_2 sequestration into aquifers are very significant. The observed reduction in the residual liquid saturation implies that a much greater quantity of CO_2 could be sequestered than would be suggested based on simple relative permeability concepts alone.

Simulations of CO_2 sequestration using numerical models based on simple relative permeability functions are likely to misrepresent the physical outcome of CO_2 injection into aquifers. Current numerical simulation programs may need to be modified to allow for the combined influences of solution/dissolution and relative permeability.

3.0 Introduction

With the increasing concern about global warming, many technologies have been developed to help mitigate carbon dioxide (CO_2) emissions to the atmosphere. The primary motivation for this research has been the mitigation technology of sequestering the CO_2 in deep geological formations, particularly saline aquifers. The technology has great potential for storing large quantities of CO_2 by two main physical mechanisms. The first physical mechanism known as dissolution works by dissolving the gas phase CO_2 into the liquid phase water. In the second case the gas phase CO_2 becomes disconnected from the main gas body and becomes trapped in individual pores, this is known as residual trapping.

In order to safely sequester CO_2 a thorough understanding of the interaction between the two separate fluid phases while passing through the pore spaces is critical. The relationship used to capture this is relative permeability, which conveys each phase's permeability relative to the permeability at 100% saturation. (Here permeability is represented as k and relative permeability as kr.) However, only a few CO_2-water relative permeability experiments have been conducted at reservoir conditions (~100bar, 40˚C), even though the relative permeability relationship is essential in properly sequestering CO_2 as an immobile phase in the pore space. The relative permeability curves implemented in a computational flow-simulator are the crucial link between the pore-scale displacement phenomena and the macroscopic flow system governed by Darcy flow. Therefore we must clearly understand the factors that influence relative permeability if we wish to safely sequester CO_2.

3.1. Project Goal

Injection of CO_2 into deep aquifers has promise as a means of carbon sequestration. As long as the CO_2 remains in the gaseous phase, then the flow properties are well understood. However CO_2 does dissolve significantly into the water phase. The flow behavior becomes significantly more difficult to predict when both water (with the dissolved CO_2) and gas (CO_2) are flowing simultaneously. In particular, the fluid flow of gas-liquid mixtures in which active phase change is taking place is a sparsely understood area of flow through porous media. Coupling this active phase change with the relative permeability relationship is very difficult because CO_2 solubility in water is a function of temperature, pressure, saturation history, and dissolved CO_2 concentration. Therefore the overall goal of this project was to investigate the importance of active phase change between CO_2-water during unsteady state displacement experiments, and to see if a standard relative permeability model could be developed to match the results.

The segmented goals for the project were as follows. The first goal of the project was to set up a physical model of water (with dissolved CO_2) and gas (CO_2) flow in a porous medium. The second goal of the project was to measure the relative permeability in the complex two-phase flow, to provide experimental data for numerical simulations and other engineering calculations related to CO_2 injection and sequestration. The third goal of the project was to investigate the fundamental mechanisms of water and gas (CO_2) two-phase flow in porous media through experimental studies. The performance of CO_2 injection and sequestration is expected to be a strong function of the two-phase relative permeability.

3.2. Project Objective

Relative permeability and other related fluid flow properties will be of central importance in numerical simulation and other engineering calculations in CO_2 sequestration into geological formations for environmental protection. However, there have been few reports on the experimental measurements of relative permeability in water and CO_2 systems. The reason may be due to the difficulty in making direct measurements because of the significant mass transfer between the two phases due to evolution and dissolution. Note that a great amount of CO_2 will be dissolved in the water phase in a water-CO_2 system. On the other hand, previous studies on phase-changing relative permeability (considering steam and water) have shown that the effect of relative permeability on the performance of geothermal energy production is very significant (Horne et al., 2000). The effect of relative permeability on CO_2 injection and sequestration may also be significant. To this end, this project was designed to model fluid flow physically and to measure the relative permeability in water-CO_2 systems directly. With the completion of this project, engineers and scientists will no longer need to use hypothetical data of relative permeability to conduct numerical simulations and engineering calculations related to CO_2 injection and sequestration. In particular, it will no longer be necessary to ignore the effect of the phase interchange on the flow properties.

3.3. Impact on Environmental Problem and Project Benefits to California

Reducing greenhouse emissions is one of the grand challenges of 21st century for the entire world. California is no exception. CO_2 sequestration is a promising approach to attack this challenge. Hence any improvement in the efficiency of CO_2 sequestration will be of direct benefit to the State in several ways:

- By providing and using fossil energy with acceptable impact on environment.
- By reducing greenhouse gases and pollution significantly, hence improving our living environment in California.
- By providing a technology that would allow for the utilization of energy that is indigenous to the State of California, and providing economic opportunities to regional California communities.

The effect of this project will be to provide a clearer understanding of CO_2 sequestration and provide a more certain estimate of its feasibility. Reducing the uncertainty will lower the risks and associated costs of CO_2 sequestration.

3.4. Scientific and Technical Background:

Disposal of CO_2 from stationary sources (power plants burning natural gas, crude oil, and coal) is an important step in reducing global carbon emissions. One possible method that has been suggested is to sequester CO_2 into deep reservoirs and aquifers. Two-phase water-CO_2 flow would exist in these reservoirs (Pruess et al., 2003). Relative permeability in water-CO_2 systems is often imposed artificially in numerical simulations for CO_2 injection and sequestration because experimental data have been lacking. The relative permeability of water-CO_2 systems will play an important role in CO_2 injection and sequestration, as well as in the evaluation of CO_2 leakage from geologic disposal reservoirs. It will be helpful for engineers and scientists to have water-CO_2 relative permeability data measured directly. Engineering risks would also be reduced if reliable relative permeability estimates can be obtained.

3.5. Previous Studies

Bennion and Bachu (2005) conducted relative permeability experiments on 3.8 cm diameter and 8.6 cm long sandstone and carbonate cores, from the Alberta basin, to evaluate the potential for sequestering CO_2 in the region's deep saline aquifers. Their experiments were conducted at reservoir conditions with pressures ranging from 160-500 bar and temperatures ranging from 20-75°C. The samples selected were representative of the formations found in Alberta with permeabilities ranging from 0.18-795 md. Their experimental research found that there is a very poor correlation between permeability, porosity, and CO_2 relative permeability. However, it was shown that there is an excellent correlation between the viscosity ratio (μ_w/μ_{co2}) and maximum relative permeability for CO_2. The more favorable the viscosity ratio, the more effectively the water is displaced, as anticipated.

Benson et al. (2006) conducted studies of carbon dioxide migration in saline formations at the pore scale (mm) and core scale (cm) using X-ray tomography. They used X-ray microtomography on a small Frio sandstone core plug with a 5 mm diameter and a length of 8 mm. At this scale, microtomography revealed the preferential pathways for CO_2. These pathways consisted of interconnected large pores and throats as expected.

With the traditional X-ray CT scan, Benson et al. (2006) used a larger core plug with a diameter of 3.8 cm and a length of 8.6 cm. A relative permeability displacement experiment was performed at room temperature with 'dry' liquid CO_2, as would be used in field operations. This means that water could evaporate into CO_2, because there was no water vapor present in the CO_2. The interesting phenomenon discovered was that the brine caused little interference to the flow of CO_2. The physical reason for this was that the CO_2 traveled through the high porosity regions of the core and the connate water on the surface of the pores evaporated into the CO_2, creating a localized low brine saturation zone, which resulted in a high effective relative permeability for CO_2.

3.6. Project Tasks

Six tasks were proposed in this project, as follows:

1. Modify and construct the experimental apparatus to model fluid flow and to measure relative permeability in water-CO_2 systems.
2. Conduct the physical simulation of two-phase water-CO_2 flow in a porous medium.
3. Measure relative permeability in water-CO_2 systems using the X-ray CT scanner.
4. Compare the experimental results in both water-CO_2 and water-N_2 systems.
5. Conduct theoretical studies and understand the mechanisms of water-CO_2 two-phase flow.
6. Develop mathematical models of water-CO_2 two-phase relative permeability for the application to reservoir engineering.

4.0 Project Approach

The project utilized physical measurements of gas-water flow in a sandstone core, using an experimental apparatus designed for this purpose. The experiments were performed at low pressures and temperatures in order to better manage and observe the effects of dissolution and evolution. All experiments were performed with an inlet pressure of 1.22 bar, an outlet pressure of 1.08 bar, a confining pressure 27.6 bar, and at 20ºC

In comparing these conditions (1.22-1.08 bar, 20ºC) with expected reservoir conditions (200-75 bar, 40˚C) one will immediately notice several drastic differences, Table 1. These differences illustrate an inherent difficulty with CO_2 sequestration. Under typical reservoir conditions CO_2 is in the super-critical region, where the fluid exhibits properties of both a liquid and a gas simultaneously depending on pressure and temperature. Therefore, to simplify the experiment and obtain consistently reproducible results a low pressure experimental procedure was utilized to investigate the effects of gas going in and out of solution (dissolution and evolution). With a pressure drop from 1.22 to 1.08 bar across the core a 11.2% evolution volume could be expected for CO_2, and only a 0.3% evolution volume for the N_2. Under reservoir conditions the evolution volume would be 3.5% with a pressure drop from 200-75 bar across the reservoir. Therefore it should be noted that in this first study of dissolution-evolution effects on relative permeability that the evolution volume of this experiment is greater than in the reservoir.

Table 1 - Calculated pure water and CO_2 properties (Garcıa, 2003).

	CO_2 This Experiment		CO_2 Reservoir Conditions	CO_2 Injection Conditions	N_2 This Experiment	
Temperature (C)	20		40		20	
Absolute Pressure (bar)	1.08	1.22	75	200	1.08	1.22
Density (kg/m^3)	1.83	2.32	250	802	1.17	1.48
Viscosity Ratio (μ_w/μ_g)	67.57	67.57	26.12	7.93	56.15	56.15
Mass Solubility (M_g/M_w)	0.16%	0.18%	5.65%	6.53%	0.00%	0.00%
Evolution Volume* (Vol gas produced /Vol Water) due to pressure change	11.2%		3.5%		0.2%	

* Example 1000ml of CO_2 saturated water at the inlet pressure would evolve 112ml of CO_2 gas at the outlet pressure in this experiment.

4.1. Core

A homogeneous, medium permeability, Berea sandstone core was selected for this experiment. The clay within the core was deactivated prior to being fitted into a high pressure titanium core holder. The core has a diameter of 5.0 cm and a length of 27.0 cm with a porosity and permeability of 0.23 and 885 md respectively. The core was monitored for any sign of reactions with the CO_2 saturated water throughout the experiments by measuring the absolute permeability, and by visually inspecting the core. No sign of any chemical reactions were observed.

4.2. Experimental System

The core holder system was designed and tested for a maximum confining pressure of 210 bar with water, while maintaining the pore pressure at 170 bar with nitrogen. The experimental system is shown in Figure 1 along with a diagram of the system in Figure 2. The high pressure titanium core holder has six pressure ports along the length of the core to allow for pressure front monitoring. The system's pressure measurements are acquired and logged by the LabVIEW data acquisition system.

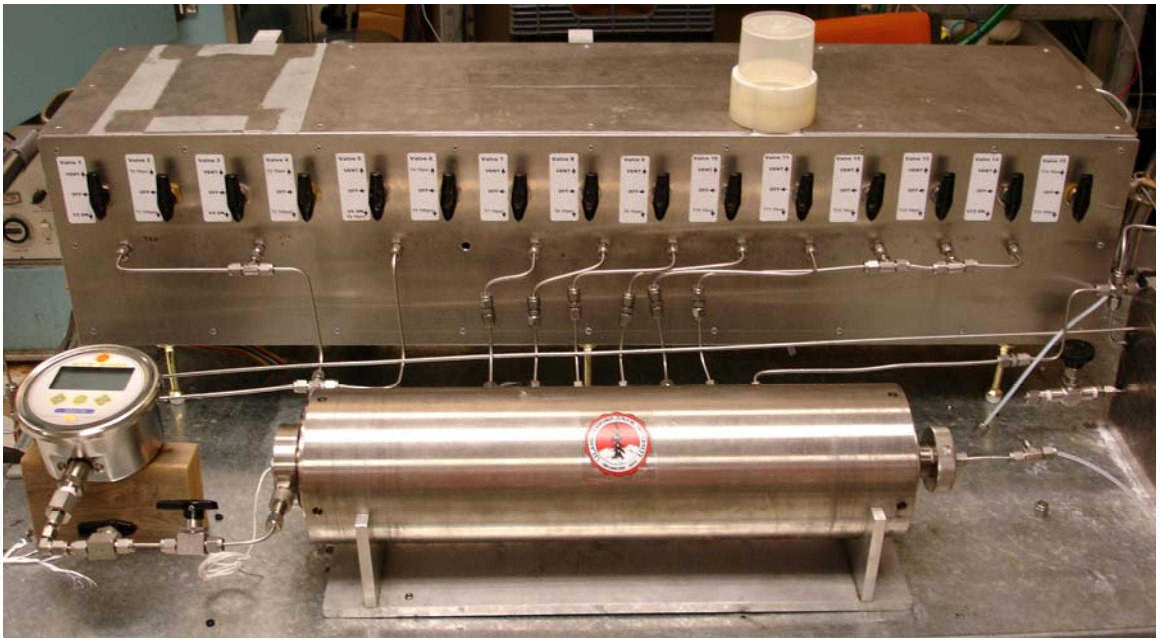

Figure 1: Image of the experimental relative permeability measurement system. The high pressure titanium core holder is in the foreground and the transducer pressure measurement system in the background.

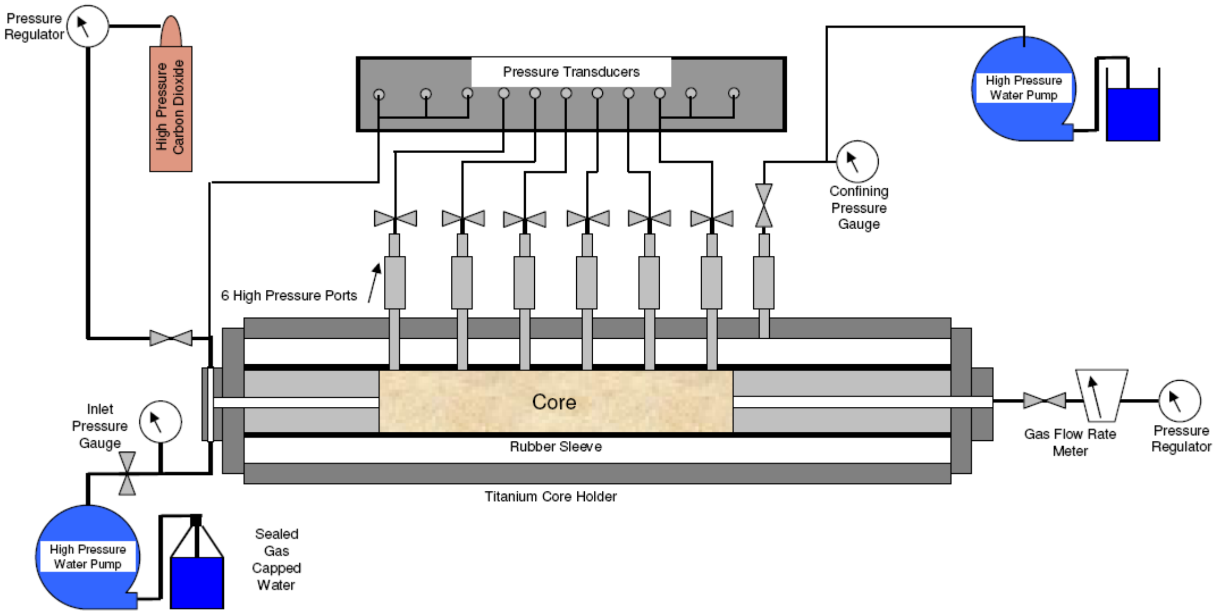

Figure 2: Schematic of experimental apparatus. The high pressure titanium core holder contains a 27cm x 5cm diameter core with six pressure ports along the length of the core. The pressure measurements are acquired and logged by the data acquisition system outlined in figure 3. The confining pressure is provided by a high pressure water pump, the carbon dioxide for drainage is provided by a high pressure gas cylinder, and the gas saturated water for drainage is provided by a water pump.

4.3. Transducer Measurement System

The pressure throughout the apparatus was acquired by the pressure measurement system as shown in Figure 3. The system works by measuring the absolute inlet pressure, the differential pressure between neighboring ports, and the absolute outlet pressure. The pressure data from the 16 transducers is then logged by the data acquisition system for analysis.

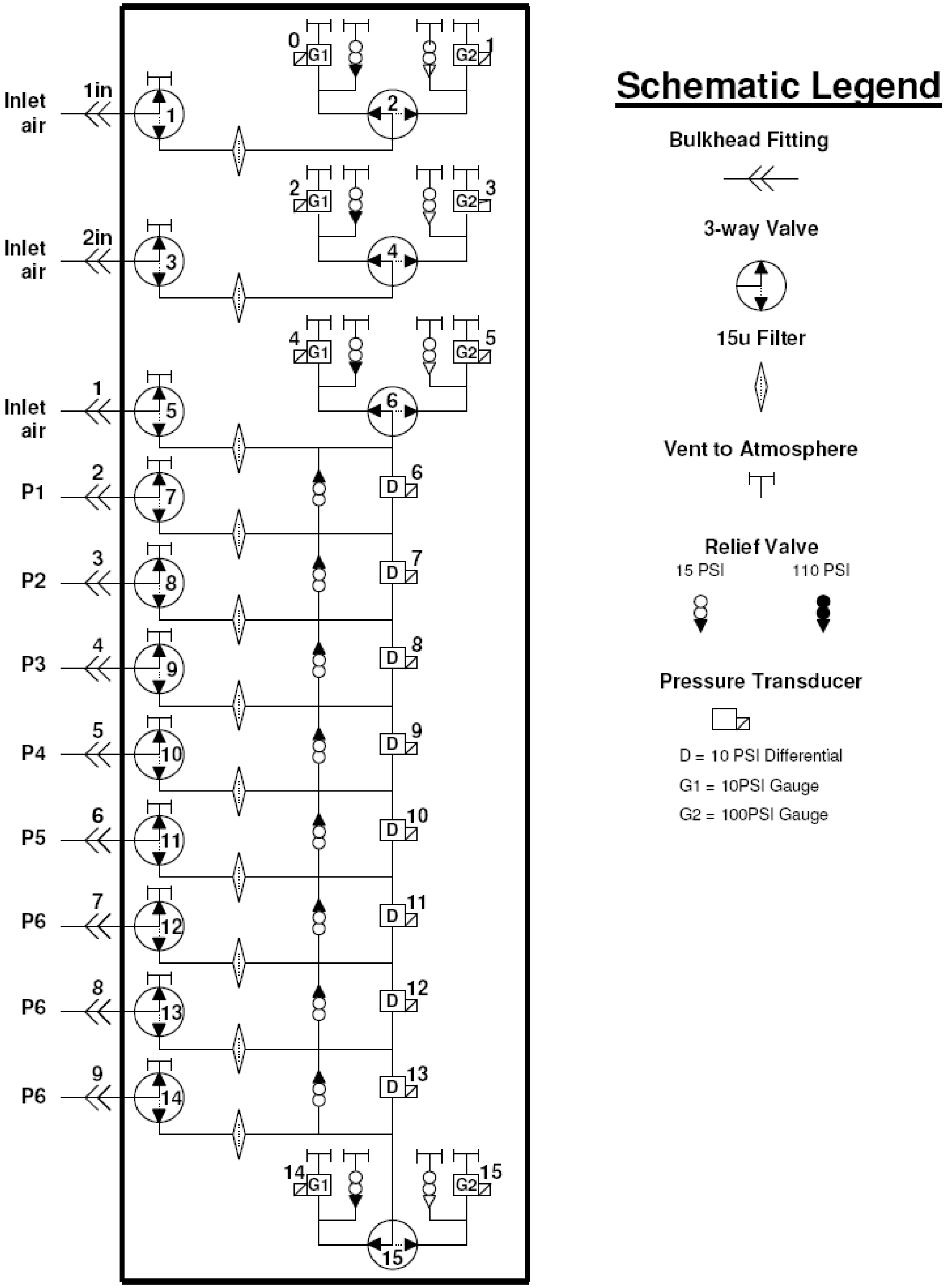

Figure 3: **Schematic of pressure measurement system. The pressure measurement system measures the absolute inlet pressure, the differential pressure between ports, and the absolute outlet pressure with a system of 16 pressure transducers.**

4.4. Experimental Procedure

Prior to each complete relative permeability experiment, the core was 100% saturated with water, which was saturated with its respective gas, at atmospheric pressure. In order to better manage and observe the effects of dissolution and evolution, the experiments were performed at low pressures and temperatures. All experiments were performed with an inlet pressure of 1.22 bar, an outlet pressure of 1.08 bar, a confining pressure 27.6 bar, and at 20ºC. This resulted in an approximate maximum injection velocity of 8.5 cm/min, which is a typical velocity in a groundwater system with a permeability of 885md (Fetter 1994).

The drainage and imbibition experiments were performed as shown in Figure 4. After saturation, the core was allowed a 24hr period to equilibrate before the first drainage was performed. In the first step, the gas pressure was increased to 1.22 bar at the inlet and remained constant until negligible water was exiting the core (~1hr). During this time the pressure along the core, the liquid production rate, and the gas production rate were monitored and logged. The gas at the inlet was then shut off, and the pressure in the core returned to atmospheric conditions for about 10min, before changing the system over to imbibition. The imbibition experiment was performed until no more gas was produced, and again all pressure and production parameters were logged for later analysis. The drainage-imbibition process was then repeated until sufficient runs had been logged.

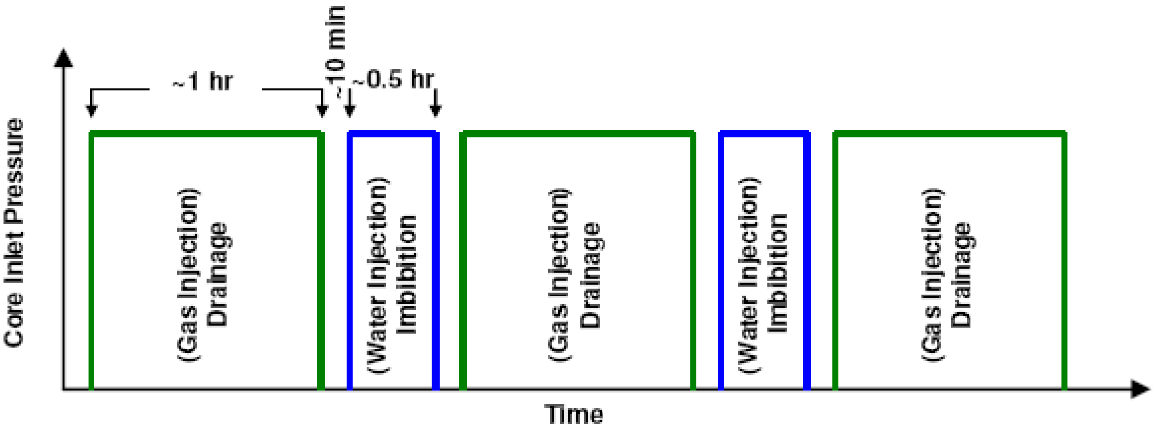

Figure 4: Graph of drainage and imbibition experiment pressure history.

The logged data was then used to calculate the drainage relative permeability by the method derived by Johnson, Bossler, and Naumann (1959), known as the JBN method. The JBN method requires knowing the pressure drop across the core, the gas flow rate, and the liquid flow rate. With these measurements, the relative permeability for each drainage step was calculated. Note: it was originally intended that the water saturation in the core would be measured using the X-ray CT approach, however, obtaining reliable images through the titanium core-holder with the

CT instrument was not possible. Ultimately, this difficulty was overcome by using the material balance method to infer saturation (this is an inherent part of the JBN approach).

The second method implemented to determine the relative permeability, and to verify the JBN method was using ITOUGH2, an inversion program for the compositional flow simulator TOUGH2, to adjust the Brooks-Corey relative permeability parameters to match the gas and water production data.

4.5. TOUGH2 and ITOUGH2 Simulations

The TOUGH2 model used was a simple horizontal homogeneous one-dimensional model consisting of 50 elements, with no gravity, no capillary pressure, and constant pressure boundaries with infinite volume.

The reason for neglecting capillary pressure was that it was found to be unrealistic and inconsequential. The capillary pressure was measured for this core in a previous study, and it was implemented initially in the simulations. However, when experimenting with the capillary pressure curve it was found that it would be impossible in the CO_2 case to reduce the saturation as far as we did with capillary pressure present. This lead to the discovery of evolution/dissolution effects on relative-permeability. Then, in the N_2 case it was found that the tests did not reach saturations low enough for capillary pressure to play a large role in adjusting the relative permeability. Therefore, to keep the analysis clear the capillary pressure was set to zero in both cases.

ITOUGH2 was used to determine the Brooks-Corey relative permeability parameters for each step of the drainage-imbibition experiment by matching the gas and liquid production data. These results are shown in Appendix A.

5.0 Project Outcomes

Multiple water flood (imbibition) and gas flood (drainage) experiments with nitrogen and carbon-dioxide were successfully performed. These experiments provided valuable insight into the effects of gas dissolution upon the relative permeability relationship in a gas-water system.

In order to properly quantify the effects of gas dissolution on the relative permeability relationship an adequate, appropriate method must be used to determine the individual relative permeability curves for each step. Therefore the JBN method was compared to the Brooks-Corey curves determined with ITOUGH2 by matching the production history. Figures 5 and 6 illustrate the matched gas and the liquid production history for the nitrogen primary drainage experiment. Figure 7 illustrates how the relative permeability curve determined by the JBN method compares to the curves determined by ITOUGH2. After matching all production histories for both CO_2 and N_2 it was observed that the JBN method does vary from the Brooks-Corey curves used in TOUGH2. Therefore it was decided to use the TOUGH2 curves throughout the remainder of the analysis.

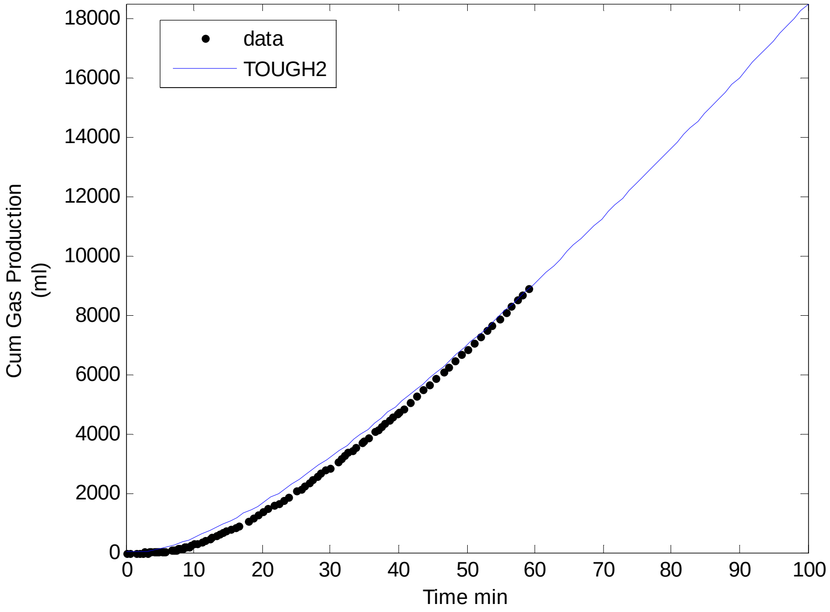

Figure 5: Cumulative gas production for the Nitrogen drainage experiment.

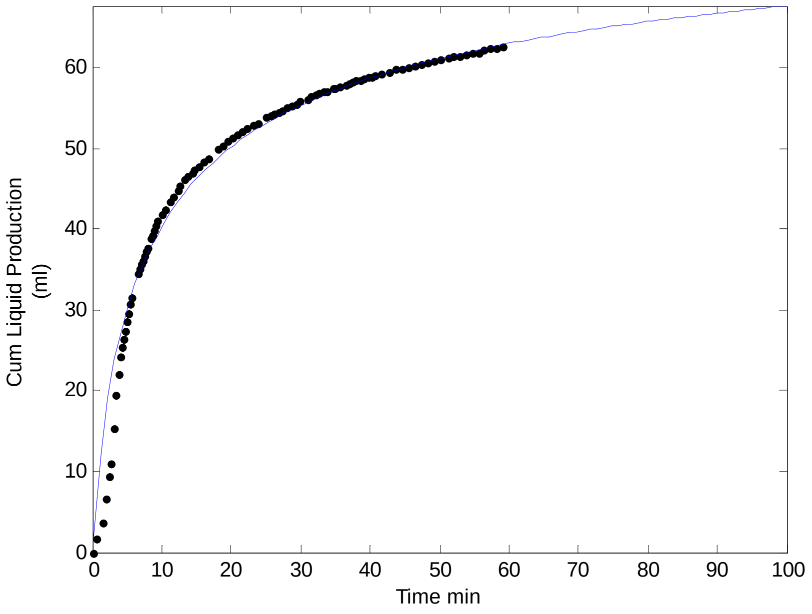

Figure 6: Cumulative liquid production for the Nitrogen drainage experiment.

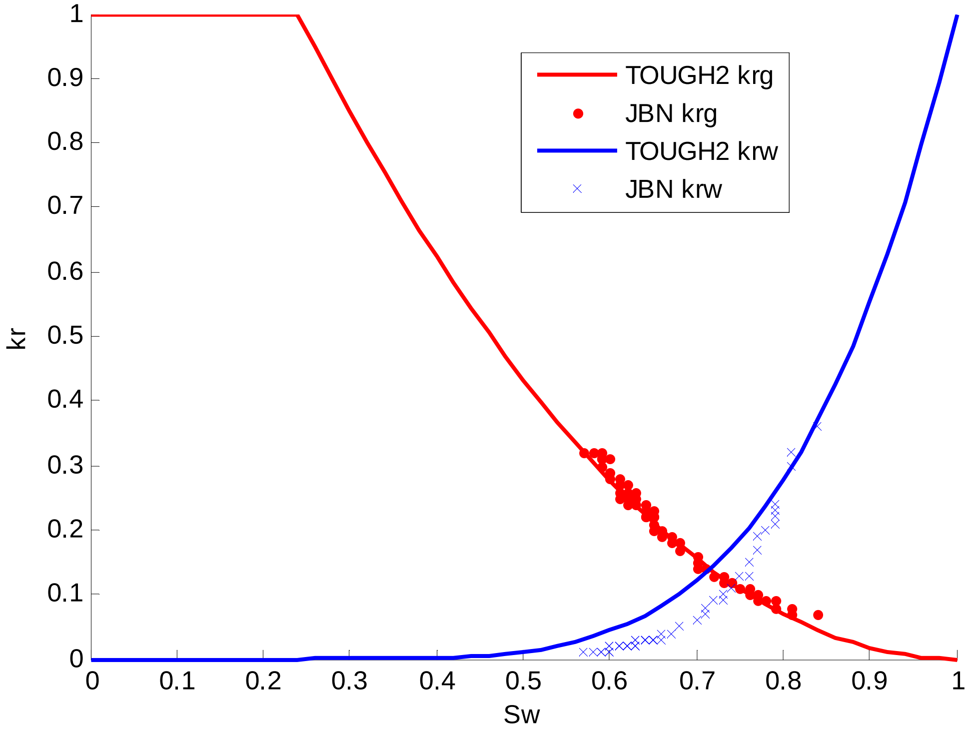

Figure 7 – Comparison between Brooks-Corey curves and JBN method for Nitrogen during primary drainage.

In this first comparison the primary drainage curves for N_2 and CO_2 are presented in Figure 8. The most striking point in this figure is the low permeability for the CO_2 in comparison to the N_2, even though the viscosity ratio (Table 1) would suggest the CO_2 should have the higher permeability. The second more subtle note is the greater decrease in residual water saturation with the CO_2, 46% compared to 51% residual for N_2.

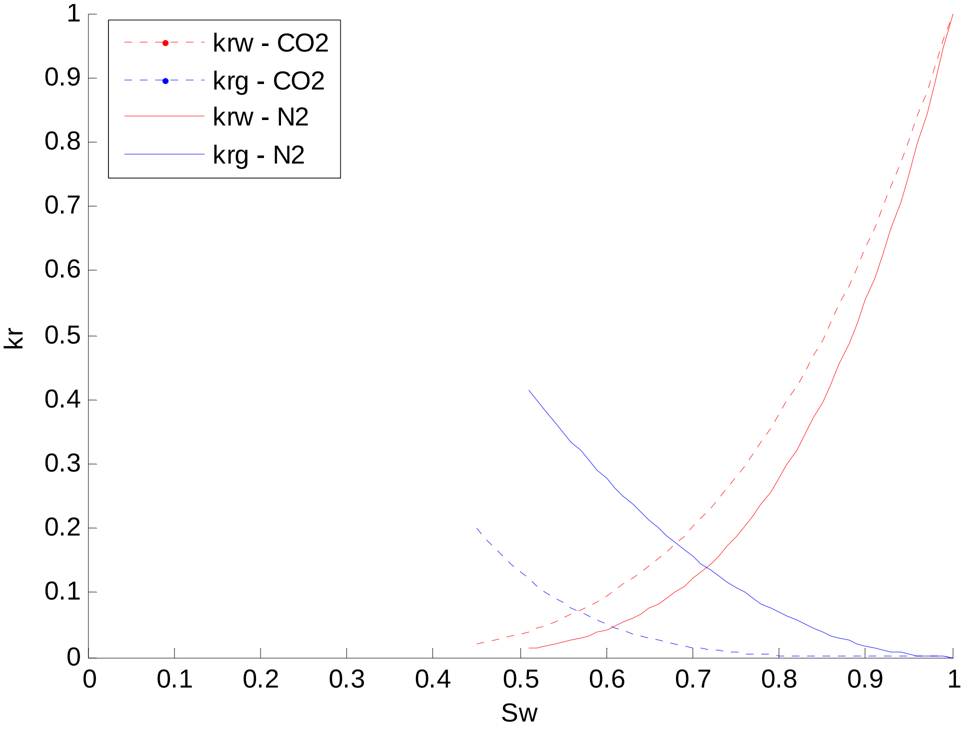

Figure 8: **Comparison between N_2 and CO_2 relative permeability curves for primary drainage. Initial S_w = 1.0,**

One explanation proposed for this is the effect of dissolution/evolution of the CO_2. Even though the core was filled with gas-saturated water, some dissolution still occurred due to the 0.22bar additional pressure applied during the experiment. When the CO_2 is injected into the core, some of the CO_2 dissolves into solution due to the increased pressure. Then, as the CO_2 saturated water moves along the core ahead of the gas front it becomes super-saturated due to the pressure decrease. Therefore the CO_2 evolves out of solution in all pores the super-saturated liquid has reached. Figure 9 illustrates this process, and for comparison to a typical displacement with negligible dissolution/evolution Figure 10 is provided. This process would negate capillary entry pressure and allow for the drainage of smaller pores, leading to a lower saturation. This also helps explain the lower relative permeability for CO_2. The dissolution-evolution is forcing the water out of the smallest pores into the high permeability pathways, also causing the water permeability to appear higher.

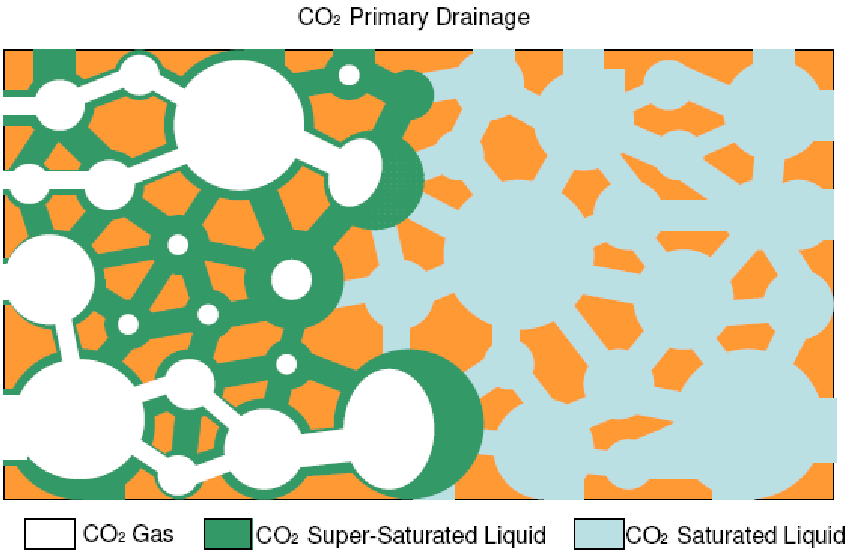

Figure 9: **Diagram illustrating the evolution of gas from disconnected pores during CO_2 primary drainage.**

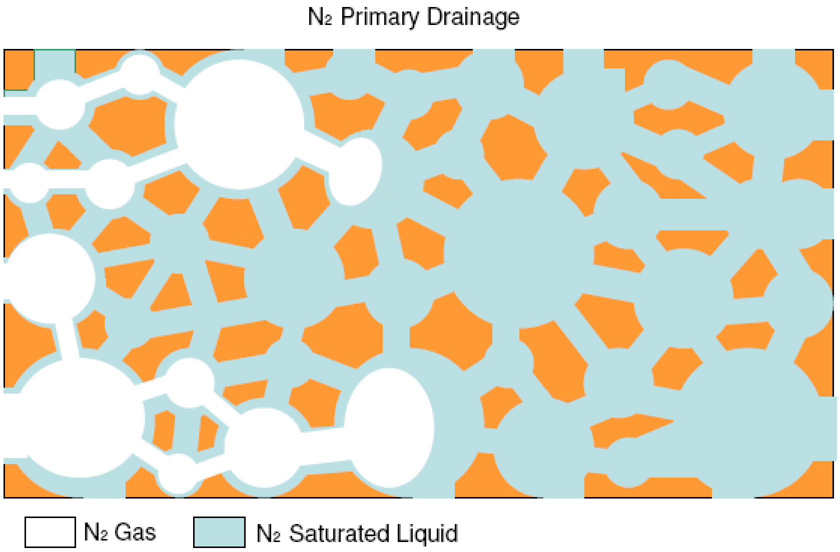

Figure 10: **N_2 primary drainage, illustrating gas displacement without dissolution/evolution.**

In this second part, a comparison is made between the hysteretic relative permeability curves determined for N_2 and CO_2 during successive drainage-imbibition cycles, Figures 11 and 12. These hysteretic relative permeability curves demonstrate the well understood idea that relative permeability is not a function of saturation alone, but is a function of saturation history. (Doughty, 2006). The underlying reason for this is capillary entrapment of the gas causes hysteresis effects in relative permeability curves, and the exact relative permeability curve followed is very dependent upon the saturation point at which drainage switches to imbibition (Lenhard et al. 1987).

These drainage experiments shown in Figures 11 and 12 were performed by conducting a primary drainage, as described earlier, flooding the core with gas-saturated water (imbibition), and subsequently repeating until three cycles were complete. The phenomenon of hysteresis is seen clearly in Figure 11, where the gas and liquid curves change only slightly through successive drainage and imbibition cycles after the primary drainage. This agrees with Lenhard's experimentally determined hysteresis curves, and the hysteretic model implemented in TOUGH2 by Doughty. However, in the case of CO_2 displacement, Figure 12, capillary entrapment cannot be the only factor causing the observed hysteresis. With each drainage and imbibition cycle, the residual water keeps decreasing and while the gas residual continues to increase, until approaching connate residual saturation, S_w=~20%. The reason for this is that the dissolution-evolution process disregards the classic idea of capillary entry pressure and hysteresis. By evolution alone, gas can form in the smallest pores, so there is no need to overcome capillary entry pressures. An important note to help further explain the continuous decrease in saturation during the switch from drainage to imbibition the pore pressure decreased to atmospheric pressure for about 10 min, Figure 4. This would cause all gas in the pore fluid to evolve out of solution until equilibrating with atmospheric pressure, thereby redistribution the fluid from the smallest pores into larger pores where it is easier to displace.

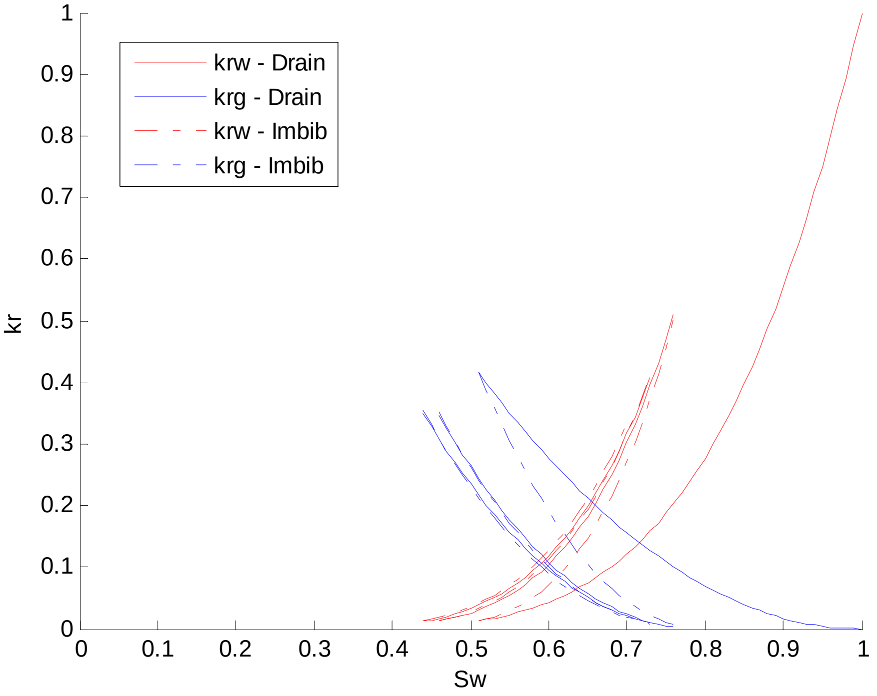

Figure 11: Relative permeability curves for N_2 displacement through three drainage and three imbibition cycles. After primary drainage the gas and liquid curves remain essentially the same, with residual water saturation S_{wr} = 45%, and residual gas saturation S_{gr} = 25%.

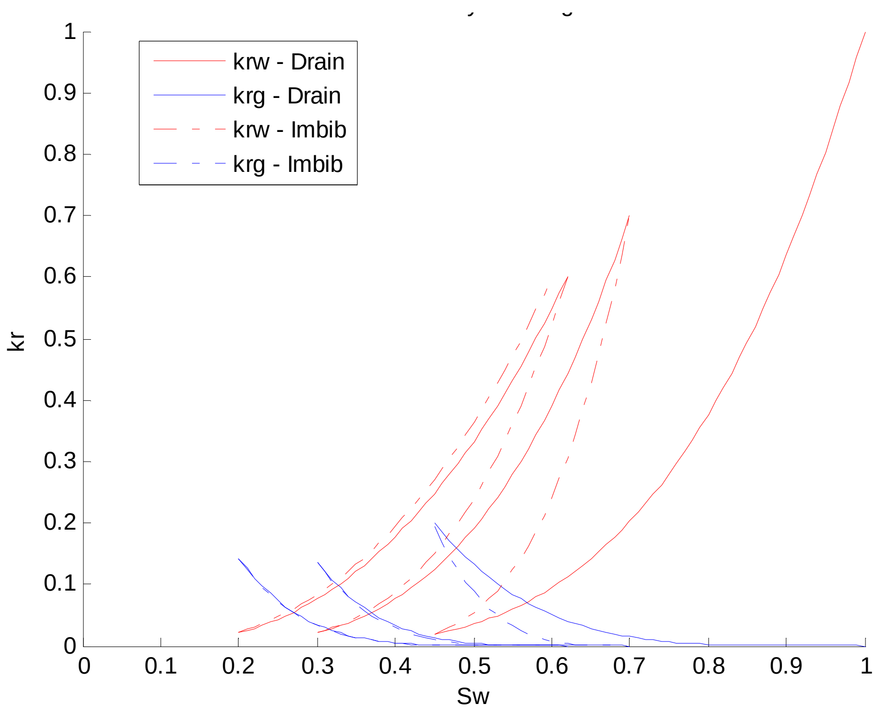

Figure 12: Relative permeability curves for CO_2 displacement through three drainage and three imbibition cycles. With each drainage-imbibition cycle the residual water saturation decreased and the residual gas saturation increases. min S_{wr} =21%, max S_{gr} = 48%.

It can be seen from these results that there is a very prominent difference between the injection of a highly soluble gas (such as CO_2) into water, and the injection of a gas with negligible solubility (such as N_2). The effects of solution and dissolution are important, and the effects will need to be included specifically in any numerical simulations of sequestration of CO_2 into aquifers. At the outcome of this theoretical consideration (Task 5), solution and dissolution were identified as the most prominent mechanisms of water-CO_2 two-phase flow. It is possible with the numerical simulator TOUGH2 to model the hysteretic behavior observed in the N_2-water case. However, TOUGH2 and all other known commercial simulators will be unable to capture the combined effects of solubility and relative permeability. This system effectively requires a new hysteretic model that not only takes into account saturation, and saturation history but also pressure history. This new model might be thought of as a 'compositional relative permeability' model, and could be an area of future research.

The curves in Figures 11 and 12 were generated with the Brooks-Corey relative permeability model, and it was initially envisaged (Task 6) that these equations could be made available for future numerical modeling. In the case of nitrogen-water flow, this is possible. However it is clear from Figure 12 that the mathematical equations that describe the measurements are not invariant, so it was not possible to arrive at a single robust mathematical formulation for the water-CO_2 relative permeability curves. Therefore the parameters for each individual curve are tabulated and attached in Appendix A.

5.1. Completion of Tasks

All six of the tasks outlined in Section 3.6 were completed, with some modifications. During the actual experiments, the material balance method of estimating saturation was substituted in place of the X-ray CT approach (Task 4), with good success. Theoretical modeling of the experiments (Task 5) was reduced to conceptual modeling, as the observations showed that the current numerical simulation programs would need to be modified to compute the transport equations. The results of this study suggest that such modifications would be useful and important to further understand water-CO_2 two-phase flow; however, this was beyond the scope of the present study.

Task 6 envisaged the provision of mathematical equations to describe the water-CO_2 relative permeability data, and curves based on such equations were derived and are shown in Figure 8, along with parameters to plot these curves are presented in Appendix A. However, the experimental results revealed the important contribution of solubility effects in water-CO_2 two-phase flow, beyond the behavior of relative permeability. Hence, classic hysteretic relative permeability curves based upon capillary entrapment alone are not sufficient to describe water-CO_2 two-phase flow completely, so no equation for classic relative permeability would be suitable.

6.0 Conclusions and Recommendations

In this project, the phenomena of CO_2 solution and dissolution were shown to have very significant effects on the displacement of water by gas injection. The residual liquid saturation was decreased in the experiments without going above the capillary entry pressure. Therefore, the standard idea of relative permeability hysteresis becomes invalid when the gas is highly soluble.

The implications of dissolution/evolution on CO_2 sequestration into aquifers are very significant. The continued reduction in the residual liquid saturation implies that a much greater quantity of CO_2 could be sequestered than would be suggested based on simple relative permeability concepts alone. In addition, simulations of CO_2 sequestration using numerical models based on simple relative permeability functions are likely to misrepresent the physical outcome of CO_2 injection into aquifers.

The scope of this investigation was to explore the impact of CO_2 solubility on relative permeability (and hence on CO_2 sequestration strategy). Given the findings, it is recommended that further study be undertaken on how best to capitalize on this physical phenomenon to maximize the effectiveness of CO_2 sequestration into aquifers. It is further recommended that research be undertaken to modify existing numerical simulation programs to allow for the combined influences of solution/dissolution and relative permeability.

7.0 References

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8.0 Appendix A

Brooks-Corey Relative Permeability Model

$$k_{rl} = \alpha \hat{S}^{\lambda}$$

$$k_{rg} = \beta\left(1 - \hat{S}^{\eta}\right)$$

Where:

$\hat{S} = \left(S_w - S_{wr}\right)/\left(1 - S_{wr} - S_{gr}\right)$ Effective saturation

S_w	Water saturation
S_{wr}	Residual water saturation
S_{gr}	Residual gas saturation
λ	Liquid exponent
η	Gas exponent
α	Liquid scale factor
β	Gas scale factor

Table 2 - Parameter values determined for CO_2 relative permeability hysteresis curves in Figure 12.

	CO_2					
	S_{wr}	**S_{gr}**	α	β	λ	η
Drainage 1	0.20	0.00	1.00	1.00	3.40	4.30
Imbibition 1	0.30	0.30	0.70	1.00	3.70	3.50
Drainage 2	0.10	0.30	0.70	1.00	3.20	4.90
Imbibition 2	0.10	0.38	0.60	1.00	3.50	4.10
Drainage 3	0.05	0.38	0.60	0.70	2.50	5.20
Imbibition 3	0.05	0.40	0.60	0.70	2.50	5.00

Table 3 - Parameter values determined for N_2 relative permeability hysteresis curves in Figure 11.

	N_2					
	S_{wr}	S_{gr}	α	β	λ	η
Drainage 1	0.25	0.00	1.00	1.00	4.20	2.00
Imbibition 1	0.36	0.20	0.72	1.00	3.80	2.10
Drainage 2	0.25	0.20	0.70	1.00	4.20	2.20
Imbibition 2	0.27	0.20	0.72	1.00	3.90	2.35
Drainage 3	0.22	0.20	0.70	1.00	4.20	2.20
Imbibition 3	0.24	0.20	0.72	1.00	3.70	2.35