# FUNDAMENTAL ANALYSIS OF HETEROGENEITY AND RELATIVE PERMEABILITY ON $CO_2$ STORAGE AND PLUME MIGRATION

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## ABSTRACT

Relative permeability is a critical flow parameter for accurate forecasting of long-term behavior of $CO_2$ in the subsurface. In particular, for clastic formations, small-scale (cm) bedding planes can have a significant impact on multiphase $CO_2$-brine fluid flow, depending on the relative permeability relationship assumed. Such small-scale differences in permeability attributable to individual bedding planes may also have a substantial impact on predicted $CO_2$ storage capacity and long-term plume migration behavior.

Relative permeability model calibration in this study was accomplished using laboratory-scale measurements of the relative permeability of Berea sandstone, as measured by Krevor et al. (2011). A core-scale model of the flow test was created in TOUGHREACT to elucidate the best-fit relative permeability formulation that matched experimental data. Among several functions evaluated, best-fit matches between TOUGHREACT flow results and experimental observations were achieved with a calibrated van Genuchten-Mualem formulation.

Using best-fit relative permeability formulations, a model of a small-scale Navajo Sandstone reservoir was developed, implemented in TOUGHREACT with the ECO2h module. The model was one cubic meter in size, with eight individual lithofacies of differing permeability, instigated to mimic small-scale bedding planes. The model assumes that each lithofacies has a random permeability field, resulting in a model with heterogeneous lithofacies. Three different relative permeability functions were then evaluated for their impact on flow results for each model, with all other parameters maintained constant. Results of this analysis suggest that $CO_2$ plume movement and behavior are directly dependent on the specific relative permeability formulation assigned, including the assumed irreducible saturation values of $CO_2$ and brine. Model results also illustrate that, all other aspects held constant, different relative permeability formulations translate to significant contrasts in $CO_2$ plume behavior.

## INTRODUCTION

Data for the relative permeability of $CO_2$ and water/brine for most reservoir rocks is lacking in the current literature. Relative permeabilities of the Navajo sandstone in particular have not been measured, or at least are not published. One of our research goals was to investigate the validity of using experimentally derived relative permeability functions for a well-known formation, in this case the Berea sandstone, to calibrate a relative permeability function effective for modeling $CO_2$ behavior in Navajo sandstone. Ideally, core flood experiments need to be set up for Navajo sandstone and the relative permeability measured, and we just began such experiments. Upon completion of the testing, we will evaluate the measured curves and compare to the relative permeability values measured by Krevor et al. (2011). Because our relative permeability testing just began, the focus of this study was to use TOUGHREACT modeling to investigate the effects of relative permeability on $CO_2$ plume movement and determine how well different relative permeability curves compare, in this context, to the experimental data measured by Krevor et al. (2011).

Initially, a numerical model of a Berea sandstone core and a Navajo sandstone core were created to model the relative permeability core flood experiment done by Krevor et al. (2011). The relative permeability curves used in the numerical models were varied, and the response of the $CO_2$ plume was studied. Next, a small-scale reservoir model was created of the Navajo Sandstone, with the idea of mimicking the layering observed at the Devil's Canyon site in southern Utah. To analyze how $CO_2$ behaves as it reaches lithofacies with varying permeability, a model was created that has four different lithofacies types, each with its own permeability values, or range of values in the case of the heterogeneous model. The model has Dirichlet boundary conditions on the top and bottom, and Neumann boundaries on the sides. A higher pressure was specified at the bottom to induce a pressure-driven upward flow across the model. This was done to study the effect that relative permeability has on $CO_2$ movement through lithofacies of different permeability.

## LITERATURE SURVEY

Compared to intrinsic permeability, $CO_2$-brine and $CO_2$-brine-oil relative permeability data are scarce, and especially so for candidate $CO_2$ sequestration formations. Krevor et al. (2011) constructed relative permeability laboratory experiments on Berea sandstone. The experimental data were fit to the Brooks-Corey relative permeability function that was modified from the original formula put forth by Brooks and Corey in 1964. Krevor et al. (2011) cites this formula outlined by Dullien (1992) as the best fit for their experimental data. We compared Brooks and Corey's original formula to Dullien's formula and discovered an error in Dullien's equation with respect to the Brooks-Corey relative permeability function. The formula 5.2.21b in Dullien doesn't match the formula developed by Brooks and Corey in their 1964 paper, equation 15. The following two equations are Equation 1 from Dullien's book and Equation 2 from Brooks and Corey (1964); note that the equation from Dullien's book expresses the exponent (2+λ)/λ on the outside of the parentheses of the third term, but in the original formula developed by Brooks and Corey, this expression (2+λ)/λ is on the inside of the parentheses, thus modifying $S_{eff}$ directly.

Equation 1. Dullien (1992)

$$k_{rnw} = \left(1 - S_{eff}\right)^2 \left(1 - S_{eff}\right)^{(2+\lambda)/\lambda}$$

Equation 2. Brooks and Corey (1962)

$$k_{rnw} = (1 - S_e)^2 \left(1 - S_e^{\frac{2+\lambda}{\lambda}}\right)$$

Bennion et al. (2007) produced laboratory measurements of potential seal rocks in the Alberta Basin, Canada and evaluated the relative permeability and capillary pressure curves for shale and anhydrites. They concluded that under normal injection pressures and reservoir conditions these formations act as seals over geologic time. Bennion et al. (2006) performed identical relative permeability and capillary pressure experiments on reservoir rock, sandstone, and carbonate formations from the same area in Alberta, Canada. They expressed the importance of relative permeability and residual gas trapping in the pore spaces as important factors affecting injectivity and $CO_2$/acid gas mobility in a brine reservoir. The authors state the importance of knowing the capillary pressure curves for the seal rock, so that injection pressures can be kept below that threshold and $CO_2$ is not forced into the seal rock. What is not discussed in these papers is the importance of using appropriate relative permeability curves and parameters for specific rocks under study when evaluating flow with numerical simulations. The numerical models developed by our team suggest that the choice of relative permeability function and parameters may have a significant impact on $CO_2$ movement and phase behavior, even causing layers to act as a barrier to $CO_2$ flow under certain conditions.

## CONCEPTUAL FRAMEWORK

A critical needs for future $CO_2$ storage efforts in the western U.S. are robust relative permeability functions for simulating multiphase $CO_2$ flow in the Navajo sandstone. A goal of this project was to analyze the $CO_2$ plume response to different relative permeability curves and compare the results to existing experimental curves for Berea sandstone. Specifically, we quantified the disparity of flow fields among results of simulations that used different relative permeability functions.

For this study, the modeling effort was approached in two phases. The first step was to recreate the Krevor et al. (2011) core flood experiments using TOUGHREACT. Then, we applied the same relative permeability curves to a small-scale reservoir model of the Navajo sandstone. The objective was to quantify the magnitude of difference between the mass flux of $CO_2$ that each relative permeability curve predicts. For the core-model simulations specified, $H_2O/CO_2$ mixtures were injected into the core at a total flow rate of 15 mL/min to determine the fluid response to different relative permeability curves. Table 1 has the injection rates used in the model. Then the same relative permeability curves were used for a small-scale reservoir simulation of the Navajo sandstone, and the results were compared to the core models to determine the validity of using the Krevor's parameters as a proxy for the unknown Navajo sandstone parameters—or if either of the other two curves yielded better results.

To determine what function would be a fair representation of the experimental relative permeability data for Berea sandstone, we created a single cell "batch" model, assigned specific $CO_2$ mass fractions, and plotted the relative permeability data against the Berea sandstone experimental data. The experimental relative permeability curve for the Berea sandstone was digitized from Krevor et al. (2011). Using these experimental data points (water saturation values), we calculated the corresponding individual relative permeability values for the Brooks-Corey formula presented by Krevor et al. (2011), the van Genuchten-Mualem function, and a simple linear function. A fundamental regression analysis determined the best-fitting parameters for each of the curves used in the subsequent models. The root mean square error (RMSE) value was then calculated for each function and compared to the experimental data, and the best "fit" was chosen to represent the experimental curve. The RMSE for the fitted van Genuchten-Mualem function was 0.007 for the wetting phase and 0.015 for the nonwetting phase; for the Brooks-Corey curves it was 0.016 for the wetting phase and 0.003 for the nonwetting phase. The difference in RMSE is close enough that the fitted van Genuchten function will work for the core simulations of this study. The other two curves used were not fitted to the Berea sandstone data. Charts 1 and 2 present the regression analysis done to justify using the van Genuchten-Mualem function.

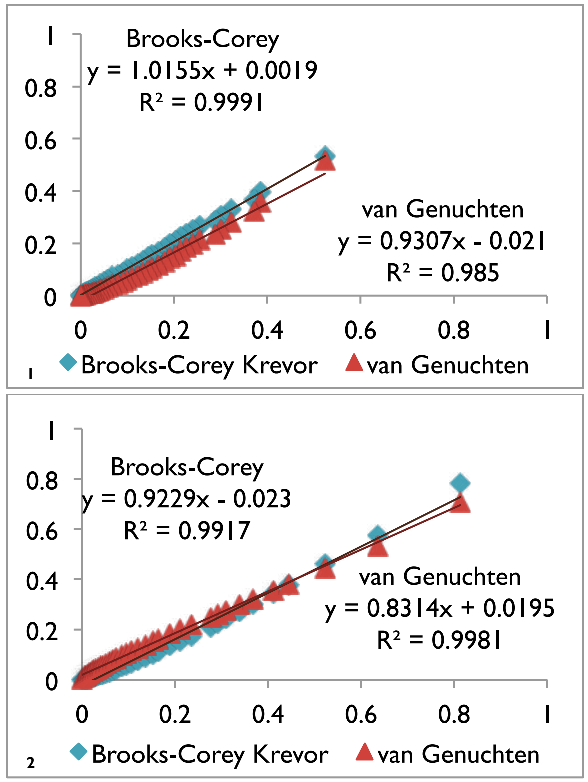



Chart 1, 2. Relative permeability of gas (Chart 1) and water, Chart 2, predicted by the Brooks-Corey and van Genuchten-Mualem functions compared to measured Berea Sandstone data. The x-axis is the fitted experimental relative permeability data and the y-axis is the predicted relative permeability data from the functions listed.

The $r^2$ values of .985 for the nonwetting phase and 0.998 for the wetting phase were very close to the experimental values, giving confidence in using the van Genuchten-Mualem function to represent the Berea sandstone relative permeability curve from Krevor's experimental data.

***Core-scale experiment***

To model the Krevor et al. (2011) core-flood experiment, we simulated eleven specific $H_2O/CO_2$ mixtures for each of the relative permeability curves studied. Each simulation had a specific ratio of $H_2O$ to $CO_2$, with a total flow rate of 15 mL/min. This was accomplished by injection of both $H_2O$ and $CO_2$ at specified mass flow rates along the injection face of the core. Each model had an initial simulation run with 100% $H_2O$ to set up the initial pressure and temperature profile, which was then used as the initial conditions for the subsequent ten simulations. Table 1 shows the $H_2O/CO_2$ mixtures and mass flow rates used in the simulations.

Table 1. Fractional flows and the associated mass flow numbers used in each injection cell of the core flood models.

| Fractional flow | | Mass flow per cell (Kg/s) | |
|---|---|---|---|
| | | COM1 | COM3 |
| $H_2O$ | $CO_2$ | $H_2O$ | $CO_2$ |
| 1 | 0 | 1.28E-06 | 0.00E+00 |
| 0.95 | 0.05 | 1.22E-06 | 1.81E-08 |
| 0.9 | 0.1 | 1.16E-06 | 3.63E-08 |
| 0.8 | 0.2 | 1.03E-06 | 7.25E-08 |
| 0.7 | 0.3 | 8.99E-07 | 1.09E-07 |
| 0.5 | 0.5 | 6.42E-07 | 1.81E-07 |
| 0.3 | 0.7 | 3.85E-07 | 2.54E-07 |
| 0.2 | 0.8 | 2.57E-07 | 2.90E-07 |
| 0.1 | 0.9 | 1.28E-07 | 3.26E-07 |
| 0.05 | 0.95 | 6.42E-08 | 3.45E-07 |
| 0 | 1 | 0.00E+00 | 3.63E-07 |

In each case, three different relative permeability/capillary pressure curves were used. They were derived from the linear relative permeability and capillary pressure function and the van Genuchten-Mualem relative permeability and capillary pressure function that are in TOUGHREACT. Two curves used the van Genuchten-Mualem function—one with the values from Pruess et al. (2004) and the other curve fitted to the data from Krevor et al. (2011)—and one curve used the linear function. The linear function and the van Genuchten-Mualem function with the Pruess parameters have been commonly used by our group to evaluate the storage potential of $CO_2$ in the Navajo sandstone. Table 2 has the parameters used for each of the functions.

A fourth relative permeability curve was evaluated using the Brooks-Corey function presented in Brooks and Corey (1964) and the parameters from Krevor et al. (2011). It showed a very good fit between the Krevor experimental curve and the curve from the Brooks-Corey function. This was expected, as it is the one cited in the Krevor et al. (2011) paper used to fit their data. But when coded into TOUGHREACT, the function would not work properly, for reasons yet to be determined. This research track was abandoned until more time could be put into determining what was causing the problems.

A numerical model of a 2 inch × 4 inch sandstone core was then built (see Figure 1). The model was created horizontally to match the experimental setup outlined in Krevor et al. (2011). The model contains 193 injection cells on the right face and an infinite-volume boundary on the left face, with no-flow boundaries everywhere else. The fluid mixture was injected at the right side of the model. The model domain has a total of 6,692 cells (see Figure 1 for the Berea and Navajo core models). The pressure and temperature were set to 9MPa and 50°C, respectively. Pure water and $CO_2$ are the two working fluids used in the simulations. All of the core simulations were run for a simulation period of four hours. The Berea sandstone core was a homogeneous model with a set permeability of 300 mD, to match the Berea core used by Krevor et al. (2011) in their study. This core model was homogeneous and had no bedding planes or other internal structures. The Navajo model has 13 individual zones modeled that are of four different lithofacies types, with each lithofacies being homogeneous. The four distinct lithofacies modeled were the grain flow (GF00x), wind ripple lamina (WRL0x), course lag (CL00x), and wind ripple lamina/grain flow (WRLGx). Table 3 has the permeability values for each of the lithofacies used in the model.

Table 2. Relative permeability parameters used by TIOUGHREACT.

| Relative Permeability Parameters | | | |
|---|---|---|---|
| | Linear | van Genuchten[1] | van Genuchten – fitted[2] |
| Lambda - $\lambda$ | n/a | 0.457 | 0.670 |
| Water i-sat. ($S_{lr}$) | 0.2 | 0.3 | 0.20 |
| Gas i-sat. | 0.0 | n/a | n/a |
| Water Sat. ($S_{ls}$) | 1 | 1 | 1 |
| CO2 i-sat. ($S_{gr}$) | 1 | 0.05 | 0.05 |

1 Pruess et al. (2004)

2 Values are modified to match the Berea sandstone as measured by Krevor et al. (2011)

Table 3. Measured permeability data from the Devil's Canyon field site. The standard deviation illustrates that there is large variability in the permeability measurements, highlighting the limitations of the TinyPERM II™ in isolating single layers in the rock matrix.

| Layer Data for Navajo Models | | | | | |
|---|---|---|---|---|---|
| Layer Name | TOUGH code | Permeability | | Standard deviation | |
| | | mD | $m^2$ | mD | $m^2$ |
| Wind ripple lamina | WRL0x | 280 | 2.76E-13 | 119 | 1.17E-13 |
| Wind ripple lamina/Grain flow | WRLGx | 388 | 3.83E-13 | 171 | 1.69E-13 |
| Grain flow | GF00x | 560 | 5.53E-13 | 311 | 3.06E-13 |
| Course lag | CL00x | 5346 | 5.28E-12 | 2329 | 2.30E-12 |

These four lithofacies represent the small-scale heterogeneities in the Navajo sandstone outcrops that were studied at Devil's Canyon, Utah during field research in the summer of 2011 (Allen et al., 2011). This site is an aboveground analog of what the Navajo sandstone is believed to be like at Gordon Creek, Utah. The permeabilities used in each layer were an average of the measured permeabilities for each layer, as measured by Allen et al. (2011). Permeabilities for each layer were measured *in situ* using the TinyPERM II™ air permeameter.

It must be noted here that the permeability values used for each of the individual layers in the Navajo model are averages of the measured values. There was large variability in the values measured for each layer in the field, due to the relatively large diameter, about 9 mm, of the TinyPERM II™ compared to the millimeter scale of the individual lithofacies observed in the outcrop. Also, there were more than the four lithofacies that are used in the model present in the outcrop; the four lithofacies used in the model represent the most common types seen in the outcrop. With such a wide variability in the measured data, the permeability values used in the model can only be thought of as an estimation of the common lithofacies seen in the outcrop. Many factors could make these values to be inaccurate, such as the effects of weathering on the permeability of the rock at the surface, or the difference in scale between the TinyPERM II™ orifice and the individual lithofacies.

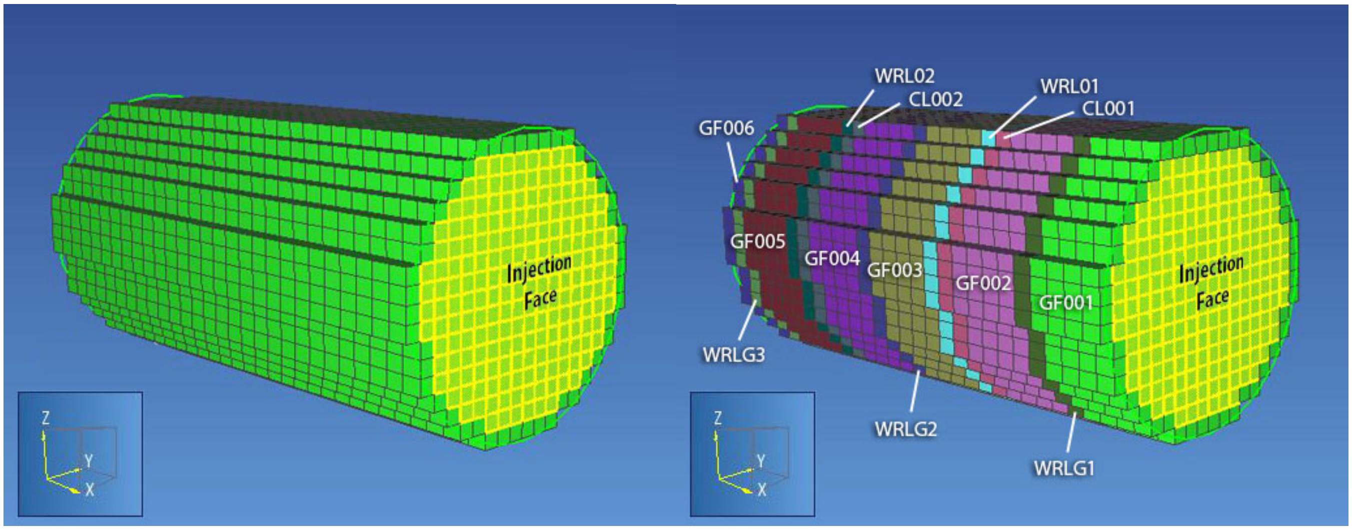


Figure 1. Berea core model on the left and the Navajo core model on the right.

***Bedform-scale experiment***

The small-scale Navajo model was built to represent an approximate one meter cube of the aeolian Navajo sandstone that is observed in the Gordon Creek area near Price, Utah. The Navajo sandstone at this location is at a depth of 2560 m below the surface, and accordingly, we assigned a hydrostatic initial condition of 25.7 MPa. The temperature is estimated to be 67.8°C at this depth, using an extrapolated linear temperature gradient based on measured values within the White Rim formation yielding a temperature gradient of 22.5°C/km (Chidsey and Chamberlain, 1996). The brine has a salt concentration of 0.36% NaCl, which is typical for the Navajo sandstone in the area surrounding Gordon Creek (Hood and Patterson, 1984).

Using this information, we built a centimeter-scale three-dimensional reservoir model, using TOUGHREACT and the ECO2h module to model multiphase flow of $CO_2$ in brine. The reservoir model consists of the same aeolian Navajo sandstone rock properties as the core model. The plan was to flow $CO_2$ through this model under a vertical pressure gradient, while varying the relative permeability curves used, to study the model's response. This model uses the same three relative permeability curves used in the core models and described above. Table 2 has the relative permeability parameters used in this analysis. The specific relative permeability equations are given in the TOUGH2 Users Manual (Pruess et al., 1999).

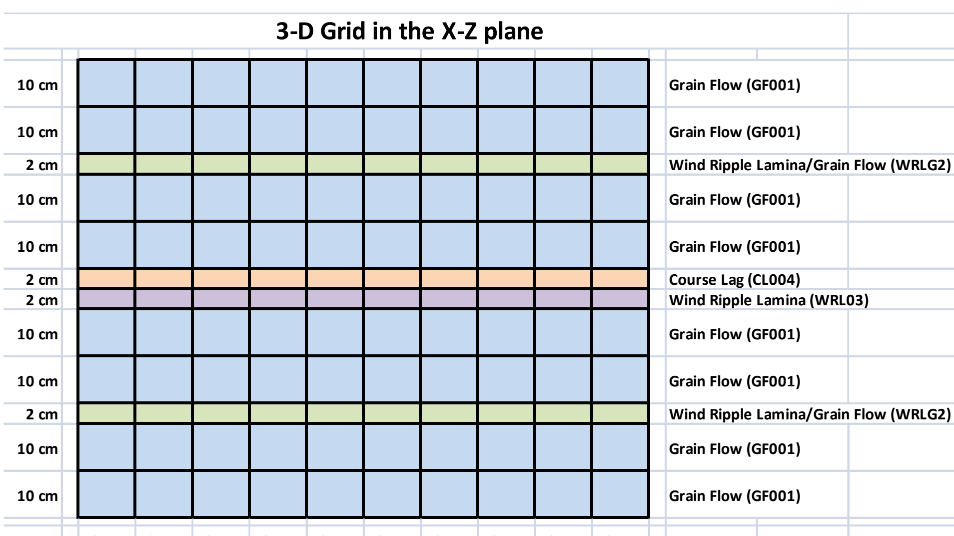
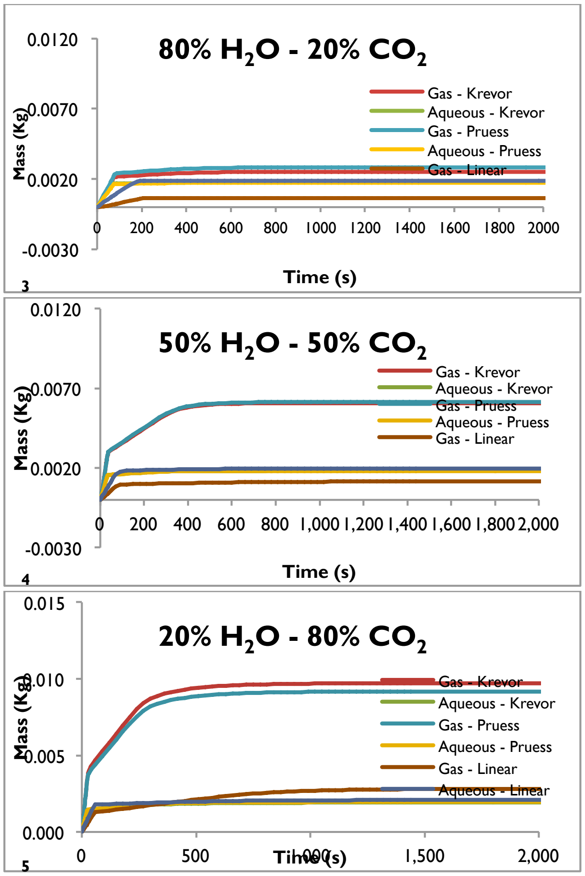


Figure 2. X-Z slice of the mesh grid used in this model.




Charts 3, 4, 5. Results of the Berea sandstone simulations showing predicted mass of $CO_2$ in place for each relative permeability curve used.

The Navajo reservoir model domain is 100 cm × 100 cm × 88 cm in the x, y, z directions; Figure 2 shows the mesh in the x-z plane. It consists of four different layer types patterned after the observed sandstone layers at Devil's Canyon Navajo. A "dummy" bottom layer was added to the bottom of the model with an "infinite volume," a $CO_2$ concentration of 0.50 mass fraction, and a pressure that was 10 kPa higher than the rest of the model. This created a pressure gradient of 10 kPa to simulate a pressure-driven flow without taking the amount of $CO_2$ present in this dummy layer into the calculations. The top layer also has an "infinite volume," allowing the $CO_2$ to flow out of the top of the model while still tracking the amount of $CO_2$ flowing through the model. This allowed the $CO_2$ to migrate upwards through the reservoir as if being forced upwards by the high pressure of an injection plume, without having to model the actual injection blocks. The four sides were assigned no-flow boundaries. The dummy layer at the bottom is not used in any of the calculations; consequently, the present amounts of $CO_2$ and phases represent what has moved through or is in place in the model. A simulation time of three hours was determined to be sufficient for the analysis planned. A 1000-year simulation was run to determine the optimal simulation time. The results indicated that the model reaches near steady state after about one hour. In the interest of saving computational time, a three-hour simulation time was used.

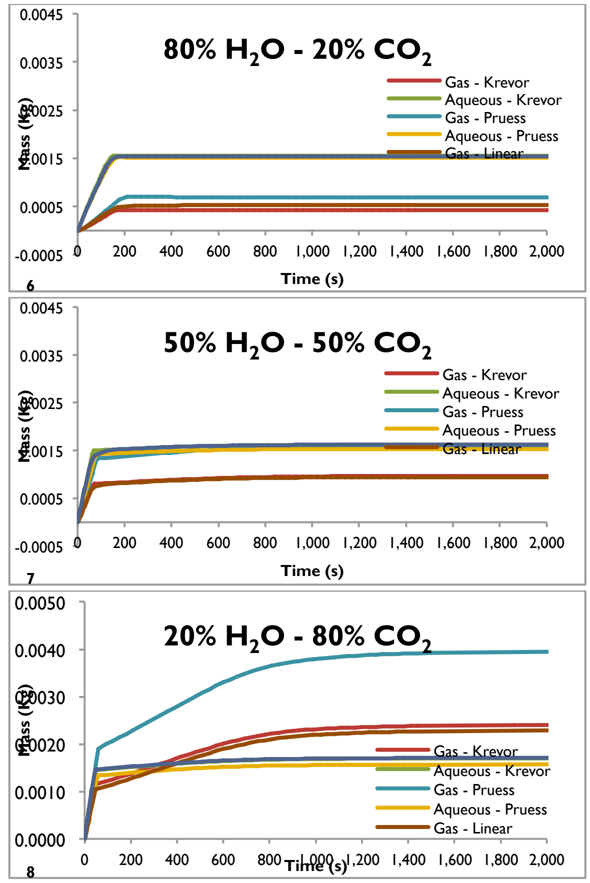
## RESULTS

For the Berea core model simulations, the Krevor et al. (2011) parameters were used as the "standard," and the results of that simulation were used as the basis of comparison. The same philosophy was used for the Navajo core model. This was done with the knowledge that the relative permeability curve for Berea sandstone was not going to be the same as one for Navajo sandstone. But even with not having an experimental curve, we still wanted to see what type of variation there was in predicted $CO_2$ using the Berea curve with Navajo sandstone rock properties.

The Berea core model simulations showed some interesting results for the predicted amount of supercritical $CO_2$ present as the relative permeability curve was varied. When between 20% and 80% $CO_2$ is flowed through the model, the Pruess curve predicts the most supercritical $CO_2$ and the linear curve the least. As the fractional flow of $CO_2$ is increased, the curve using the Pruess parameters predicts an ever-decreasing amount of $CO_2$ compared to the Krevor curve. The Pruess curve goes from overpredicting (by about 12%) to under predicting (by about 5%) the mass of supercritical $CO_2$ in place as the fractional flow increases above 50%. At 50% Pruess overpredicts supercritical $CO_2$ by only 1.1%. The linear curve consistently underpredicts the amount of $CO_2$ in place by 70–80%. This trend is illustrated in Charts 3-5. As can be seen by these charts, there is almost no difference in the predicted amount of dissolved $CO_2$ between the different relative permeability curves. This indicates that the choice of relative permeability curves does not have an appreciable impact on predicted amounts of dissolved $CO_2$ in the same way it does for the supercritical phase.

The Navajo core-model simulations show a very different response to the relative permeability curves used then the Berea model did. With the Krevor curve as the "standard," the Pruess curve consistently overpredicts the mass of supercritical $CO_2$ in place by more than 50%. The linear curve is within a couple of percent of the Krevor curve predictions for most of the simulations. It only overpredicts supercritical $CO_2$ by 20% for the lower $CO_2$ fractional flows, 20% and lower. The dissolved $CO_2$ predicted by the linear and Pruess curves is within a few percent of that predicted by the Krevor curve, indicating again that the relative permeability curve chosen has little impact on the predicted mass of dissolved $CO_2$. Charts 6-8 clearly show this trend in the supercritical and dissolved $CO_2$.

When these same relative permeability curves were applied to the small-scale Navajo sandstone model, the results were quite different from the core model simulations. Again, using the Krevor curve as the standard, the Pruess curve overpredicts the mass of supercritical $CO_2$ in place by almost 40% and the dissolved $CO_2$ by 6%. The linear curve preformed even worse, overpredicting the total mass in place of supercritical $CO_2$ by 144% and underpredicting the dissolved $CO_2$ by 22%.




Charts 6, 7, 8. Results of the Navajo sandstone core simulations showing the predicted mass of $CO_2$ in place for each of the relative permeability curves used.

The really interesting result from this simulation was that both the van Genuchten-Mualem function with the Krevor parameters and the linear function indicated that both phases of $CO_2$ moved completely through the model. The van Genuchten-Mualem function with the Pruess parameters indicated that both the supercritical and dissolved $CO_2$ phases got trapped by the lower permeability WRL lithofacies. It indicated that only a small amount of aqueous $CO_2$ moved into the upper GF lithofacies, and no supercritical $CO_2$ was present at all in the WRL, CL, and upper GF lithofacies. Chart 9 shows the mass of $CO_2$ predicted for these simulations, and the trend with the Pruess curve can be seen clearly.

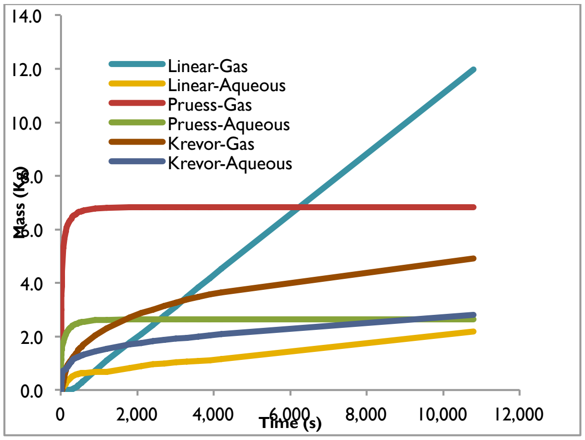



Chart 9. Results of the small scale Navajo sandstone model. The chart highlights the difference in mass of $CO_2$ that each relative permeability curve predicts.

## CONCLUSION

The results of this analysis has shown that the choice of relative permeability function and the parameters used in that function can have a huge impact on predicted $CO_2$ plume migrations, phase behavior, and storage capacity. It was clear that having experimentally derived relative permeability curves for the target reservoir is essential for getting accurate predictions of the amount of $CO_2$ and phase behavior. Our study has indicated that the dissolved $CO_2$ phase is not very sensitive to the relative permeability curve used, but the supercritical phase is. Accurate relative permeability curves for the material being studied are essential for good predictions of $CO_2$ storage capacity and plume movement. Another important finding was that using an experimentally derived curve for one material, Berea sandstone in our case, as a proxy for a different material, Navajo sandstone, yields completely different $CO_2$ plume behavior and predicted mass in place. This gives weight to the idea that unless there are good measured relative permeability curves for the particular formation being studied, using a general curve such as the linear relative permeability curve will yield conservative predictions of $CO_2$ mass and plume behavior.

One finding that was somewhat surprising was that lower permeability lithofacies within what is normally thought of as a homogeneous medium, as the Navajo sandstone is, can act as an effective seal against the movement of $CO_2$ under certain relative permeability curves. This phenomenon was only observed in the small-scale Navajo simulation and not in either of the core flood simulations. It highlights the finding that using the wrong function or parameters can lead to erroneous predictions of $CO_2$ behavior. In the case of the small-scale Navajo simulations using the Pruess curve traps the $CO_2$ below a lithofacies with a lower permeability. This study has shown how critical it is to understand the relative permeability of the reservoir rock in question. Having a relative permeability curve derived from experimental data on the rock unit under study will greatly increase the accuracy of the model's predictions of $CO_2$ phase behavior and plume movement.

To summarize the important findings of our study:

1. Choice of relative permeability function and parameters can have a significant impact on predicted $CO_2$ plume migration, phase behavior, and storage capacity.
2. Using an experimentally derived relative permeability function and parameters from one material as a proxy for a different material can yield results worse than if a generic function and parameters were used.
3. Under certain conditions, the relative permeability parameters used can cause lower permeability lithofacies to act as effective seals to $CO_2$ movement.

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