A simple approximate semi-analytical solution for estimating leakage of carbon dioxide through faults
Christopher Zahaskya, Sally M. Benson

Abstract

Assuring CO2 storage security is essential for the widespread implementation of carbon capture and sequestration. Appraising the potential for leakage through faults in seals is an important component of site screening, assessment, and selection. The focus of this study is to understand and quantify the potential rates of CO2 leakage via faults and fractures which could provide fluid migration pathways from the storage reservoir to overlying aquifers.

Several analytical solutions exist for estimating rates of fluid migration between reservoirs via faults or leaky wells [1, 2, 3, 4, 5, 6, 7, 8]. However, there is little focus on leakage up finite length faults. Here we present a new semi-analytical approximate solution for CO2 leakage through a finite length fault zone that relies on a derivation similar to that of calculating the single phase flow rate through a series of units. Under many conditions, this solution provides a good first order estimation of the amount of CO2 that leaks into the overlying aquifer relative to the amount of CO2 injected into the system with only basic knowledge of system geometry and permeability values.

Detailed sensitivity analysis of simulation models was performed in order to understand which fault and reservoir parameters most strongly influence leakage rates of CO2 from storage reservoirs. Based on this analysis the three most important parameters were, in order of sensitivity, reservoir permeability, fault permeability and aquifer permeability. With these results, a semi-analytical approximation was developed which relies almost entirely on these permeabilities and the geometry of the system (ie. reservoir and aquifer height, fault thickness, etc.) While this solution does not incorporate multiphase fluid flow properties, it still provides a good approximation for CO2 leakage from a saline aquifer especially when the relative permeability characteristic curves result in mobility ratios near one for typical CO2 saturation values in the plume, which is common for Brooks-Corey relative permeability curves and viscosity ratios for supercritical CO2 and brine at reservoir conditions. Results from this semi-analytical solution are compared to over 50 different numerical models with different fault geometries and locations and a wide range of permeability values for the reservoir, fault and overlying aquifer. Overall, leakage predictions from the analytical solution compare very well with the numerical simulations. The approximation improves when faults are assumed to have no capillary pressure however many cases with capillary pressure are examined. Finally, the approximation is more accurate at lower leakage rates (leakage <10% of total CO2 injected) because higher leakage rates create distorted plume geometry in the storage reservoir, causing the radial flow assumptions of the solution to break down.

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Nomenclature

- \( c_t \): total compressibility (Pa\(^{-1}\))
- \( f_l \): fault length (m)
- \( f_w \): fault width (m)
- \( g \): gravity (m/s\(^2\))
- \( h \): layer height (m)
- \( h_a \): aquifer height (m)
- \( h_r \): reservoir height (m)
- \( h_c \): caprock height (m)
- \( k \): permeability (m\(^2\))
- \( k_a \): aquifer permeability (m\(^2\))
- \( k_{fz} \): fault permeability parallel to flow (m\(^2\))
- \( k_r \): reservoir permeability (m\(^2\))
- \( L \): leakage fraction (-)
- \( l \): length of unit (m)
- \( \phi \): porosity (-)
- \( \Phi \): flow potential (m\(^2\)/s\(^2\))
- \( \Phi_a \): flow potential at base of fault (m\(^2\)/s\(^2\))
- \( \Phi_b \): flow potential model boundary (m\(^2\)/s\(^2\))
- \( \Phi_f \): flow potential at the top of the fault (m\(^2\)/s\(^2\))
- \( p_a \): pressure at base of fault (Pa)
- \( p_b \): pressure model boundary (Pa)
- \( p_i \): initial pressure (Pa)
- \( p_f \): pressure at the top of the fault (Pa)
- \( q_a \): flow rate in aquifer (m\(^3\)/s)
- \( q_r \): flow rate in reservoir (m\(^3\)/s)
- \( q_f \): flow rate up fault (m\(^3\)/s)
- \( \rho \): fluid density (kg/m\(^3\))
- \( r_a \): fault distance from injection well (m)
- \( r_b \): extent of pressure response (m)
- \( r_{ba} \): extent of pressure response in aquifer (m)
- \( r_{br} \): extent of pressure response in reservoir (m)
- \( r_f \): equivalent radius of fault (m)
- \( S_{lr} \): Corey curve water residual trapping (-)
- \( S_{gr} \): Corey curve gas residual trapping (-)
- \( t \): time (sec)
- \( u \): Darcy velocity (m/s)
- \( \mu \): viscosity (Pa.s)
- \( w \): layer width (m)
- \( W(u) \): well function (-)
- \( Z \): vertical length (m)

1. Introduction

One of many options available to contribute to the reduction and stabilization of anthropogenic emissions is the implementation of carbon capture and sequestration (CCS) [9, 10]. CCS has tremendous potential to aid in the reduction of global carbon emissions until energy systems around the world transition from carbon intensive fuel sources to renewable and emission-free energy sources. Despite the promise of global CO\(_2\) emissions reductions,
CCS has been confined to a small fraction of large CO₂ emissions point sources around the world. While economic hurdles (e.g., governmental climate policy uncertainty, first-of-a-kind technology risks, and added costs of electricity generation with CO₂ capture) provide the largest barrier to widespread implementation of CCS, some questions remain related to the short and long-term storage security. There are several mechanisms which have the possibility of compromising the security of supercritical CO₂ stored in deep saline aquifers or depleted oil and gas reservoirs [11]. The two most prevalent risks of leakage are via abandoned wells and fault or fracture zones. These features have the potential to provide fluid migration pathways from the storage reservoir to overlying aquifers or even to the earth’s surface. Prevention of leakage from storage reservoirs requires improved understanding of fault and fracture flow behavior, improved site characterization, better storage risk assessment, and a holistic monitoring and verification program.

The permeability of fractures and fault zones is not well constrained and is known to be dependent on host rock composition, stress history, slip distribution, confining pressure, interaction between fault segments, deformation mechanism and burial history/lithification [e.g. 12]. With this and the variation in reservoir geology, it is often difficult to even make generalizations about fluid flow behavior in fault zones because of complicated interactions between these different factors. In order to evaluate the influence of different parameters on the leakage rates of CO₂ from the storage reservoir a multi-stage sensitivity analysis is performed. First, a linear trend screening is used to reduce the number of factors (i.e. fault width, caprock thickness, etc.) so that a factorial design experiment can be performed in order to rigorously evaluate the most influential system parameters. Using this methodology, the factors with the most significant impact on the response (i.e. CO₂ leakage through the fault zone) can be clearly identified.

With this information, it is then possible to simplify the characterization of the system by focusing only on parameters that significantly influence leakage of CO₂. This allowed the development of a simple analytical expression for estimating leakage based only on single-phase flow parameters and geometry of the reservoir, aquifer and fault zone. This analytical expression is based on the Darcy velocity equation and the general pressure equation which are ubiquitous in descriptions of single and multiphase flow in porous media. The solution is tested for a number of system geometries and permeability combinations. The information gained from this work can be used to identify storage sites that have either a high or very low risk of leakage from the storage reservoir.

2. Methods and model development

2.1. Fault Characterization

Faults and fractures are observed in nature at scales ranging from tectonic to thin sections. Subseismic fault zones or fault zones which are below the resolution of most surface seismic surveys and thus could easily go undetected during site characterization are the specific focus of this study. While the subseismic threshold can vary based on fault properties and observation techniques, it is generally considered to include fault zones with displacements or offsets of less than 10 meters [13, 14, 15]. Based on this initial constraint of fault displacement, published correlations between fault displacement and fault length [16, 17, 18, 19, 20, 21, 22, 23], and fault displacement and fault width [24, 25, 26, 27], can be used to estimate fault zone geometry. Results of this characterization describe a fault which is modeled with negligible slip (i.e. no offset of the reservoir units), is 500 m in length, 100 m in vertical extent, and three meters in wide.

2.2. Simulation Model Development

After establishing some constraints on the geometry and permeability of subseismic fault zones, this information is used for constructing a 3D simulation model as shown in Figure 1. In this model, CO₂ is injected into the lower reservoir; the CO₂ plume migrates some distance in the reservoir and then reaches a fault zone that cuts across the seal and provides a pathway between the reservoir, caprock and overlying aquifer. Starting with this simple model it is possible to identify a range of possible leakage rates based on different fault permeabilities. The modeling in this study is performed on models with simple geometry and boundary conditions and fairly coarse gridding away from the fault and injection zones. There are several reasons for relying on these types of simplified models. First, these
models are easier to construct, require less grid refinement and usually allow for much faster simulation run times. Second, the goal of this work is to develop an understanding of the underlying physics of the problem of CO₂ leakage through fault zones. By starting with simple models it is easier to identify the factors that most strongly influence leakage. Finally, with these simplified models it is often possible to verify or generalize simulation results with established analytical solutions.

All simulations are performed with TOUGH2, a fully implicit numerical simulator designed to model nonisothermal, multiphase, multicomponent flow in porous and fractured media [28]. TOUGH2 was run with the fluid property module ECO2N. ECO2N enables the inclusion of CO₂, NaCl and water mixtures [29].

The base-case simulation model developed is 2.5 km by 2.5 km by 100 m, with structured grid geometry (Figure 1). The grid is locally refined around the injection well and fault zone. The smallest grid cells are one meter wide in the fault and three meters wide at the injection well. The largest grid cells are 500 m wide near the model boundaries. The lower reservoir has a thickness of 68 m, the caprock is 12 m thick and the overlying aquifer is 20 m thick. The storage reservoir and overlying aquifer both have permeabilities of 28 mD and porosities of 10%. The caprock has a permeability of 0.2 nanodarcy and a porosity of 5%. In order to model the hydrogeological response in a basin scale reservoir, the boundary cells have volume factors of 10⁻⁵⁰. The fault is based on the detailed characterization of a typical subseismic fault (Section 2.1) which is modeled with negligible slip, is 500 m in length and three meters in wide. For simplicity, the permeability structure of subseismic fault zones that typically exists in sedimentary rocks is ignored and assigned a single value. The distance of the fault from the injection well is 500 m.

The aquifer and reservoir porosity, permeability and characteristic capillary pressure curves are modeled after the Arqov sandstone as described in [30]. The characteristic capillary pressure curves for the fault and caprock are determined by scaling the Arqov capillary behavior using the Leverett function. The characteristic relative permeability curves are Corey’s Curves with S_r=0.2 and S_g=0. The reservoir temperature and pressure conditions are established based on typical values for a reservoir located at a depth of roughly 1600 m below the water table. The simulations are run in isothermal mode. In these experiments, CO₂ is injected at a rate of 7.9 kg/s (0.25Mt/yr) into the lower reservoir over a completion interval of 0 m to 55 m from the bottom of the reservoir.
3. Sensitivity Analysis

3.1. Experimental Design

Sensitivity analysis is performed in order to compare the influence of various fault and reservoir system parameters on rates of leakage from the storage reservoir. A common method for performing response analysis is the experimental design technique [31]. The experimental design in this study took place in two stages. A linear trend screening was performed first, in order to narrow down a large number of factors to 3 or 4 factors which could then be explored in greater detail with a factorial design experiment.

The first step in the linear trend screening was to determine the parameters or factors of interest. For this study, fault related factors include; thickness, permeability, porosity, capillary pressure and fault core permeability. The system factors evaluated include; caprock dip, reservoir permeability, reservoir permeability anisotropy, and overlying aquifer permeability. For each factor a low leakage, high leakage, and base value were selected in order to span a realistic parameter space. This step is the most subjective step of the sensitivity analysis because the influence of a given factor is often highly dependent on the range of the values chosen over which to test this factor. The reservoir and aquifer permeability levels were chosen by starting with the permeability value of 28 mD given in the characterization of the Arqov sandstone in [30]. The range was chosen to be an order of magnitude larger and an order of magnitude smaller. This range of reservoir and aquifer permeabilities span the typical range of values seen in saline aquifers and other potential storage sites. Other reservoir attributes were selected based on values of typical saline aquifer properties [32]. The fault zone attributes were selected based on the fault zone characterization which was briefly described in Section 2.1. The fault core permeability factor refers to the scenario where the fault damage zones have permeabilities different from that of the fault core, or center of the fault zone in the simulation model. Two fault core permeabilities were tested; the permeability of 2 \times 10^{-5} mD corresponds to a fault core containing shale smear. The permeability of 0.1 mD corresponds to a fault core in which grain size reduction associated with cataclasis results in a permeability reduction of one to three orders of magnitude relative to the reservoir permeability. A summary of the factors and levels chosen is shown in Table 1.

| Factors                      | Levels            |
|-----------------------------|-------------------|
| Reservoir permeability (mD) | 280, 28, 2.8      |
| Aquifer permeability (mD)   | 280, 28, 2.8      |
| Fault permeability (mD)     | 100, 10, 1        |
| Fault thickness (m)         | 9, 3, 1           |
| Fault core permeability (mD)| 2E-5, 10, 0.1     |
| Fault capillary entry pressure (Pa) | 9.8E-5, 3.1E-4, 0|
| Vertical reservoir permeability (mD) | 280, 28, 2.8 |
| Caprock dip (degrees from horizontal) | -4, 0, 4        |
| Fault porosity (%)          | 5, 10, 20         |

Once the three levels for each factor were chosen, simulation were run in which one factor is changed to either the high or low value while all of the other factors stay the same. For each simulation, the leakage percent was calculated where leakage percent is defined as the total mass of CO\textsubscript{2} in the upper aquifer divided by the total mass of CO\textsubscript{2} injected into the system at a given time. The leakage percent was calculated after 40 years of CO\textsubscript{2} injection, at which point an approximately steady-state leakage rate was reached. The high leakage, low leakage, and base leakage values were plotted for each factor. A linear line was then fit to these values using the least squares technique. The slope of the line for each factor is then an indicator of sensitivity where a high slope corresponds to a high influence on CO\textsubscript{2} leakage and a small slope correspond to a low influence on CO\textsubscript{2} leakage. The slopes of each factor are plotted in Figure 2. The lines are normalized so that they are all centered at 0 for the base case.
3.2. 3³ Factorial Experiments

Based on the results of the linear trend screening, the fault permeability, reservoir permeability and aquifer permeability were found to have the largest influence on leakage rates. In order to perform a more rigorous analysis of these factors, two $3^3$ factorial design experiments were run. The first experiment was designed to test which of the top three aforementioned parameters most greatly affected leakage rate. The second experiment was intended to verify that the variance method isolated the most important factors. In the second experiment the three factors chosen were fault permeability, aquifer permeability and fault thickness. Since fault thickness was identified as a parameter that had less influence on leakage rates in the variance test, it is expected that fault thickness is not sensitive relative to fault and aquifer permeability in the factorial design experiment.

Each of the factorial experiments required 27 simulations to test every combination of the three factors at three different levels. Standard regression analysis was performed [33] on the results of these factorial experiments. Calculated standardized regression coefficients are plotted as tornado plots in Figure 3 and Figure 4. In these figures bars on the positive side of the x-axis indicate that higher factor values (e.g. higher permeability) lead to higher leakage whereas negative bars indicate that higher factor values lead to lower leakage values.

As shown in Figure 3 and 4, the interactions between factors are also considered. Interactions arise when two variables influence the response in a non-additive way. A good example of this is the interaction between fault permeability and aquifer permeability. While each of these parameters is individually important, the interaction is also important because if fault permeability is very low, then aquifer permeability has little influence on the leakage rate. Conversely, if fault permeability is very high and aquifer permeability is very low then CO$_2$ traveling up the fault is not able to penetrate into the aquifer, thus negating the influence of the fault permeability.

This sensitivity study indicates that the reservoir permeability is the most influential parameter affecting leakage rates. After this, aquifer permeability and fault permeability play the largest role in determining the leakage rate. In addition, results from the second experiment verify that the linear trend screening method provided a good approximation of the relative significance of the different factors. While fault width may be considered statistically significant on determining the rate of CO$_2$ leakage, it is much less significant than fault or aquifer permeability.
4. Approximate Analytical Model for Estimating Leakage

Several analytical solutions exist for estimating rates of fluid migration between reservoirs via faults or leaky wells [1, 2, 3, 4, 5, 6, 7, 8]. Here we present a new semi-analytical solution that is simple enough for quickly screening the risk of a storage site or determining potential leakage rates from a given system. Under many conditions this solution provides a good first order analysis of potential CO\(_2\) leakage rates from the storage reservoir with only basic knowledge of system geometry and permeability values. The reason such a simple solution is possible is because, as the sensitivity results show, the permeability of the fault, aquifer and reservoir are the dominant parameters in determining leakage rates.

The system geometry of the problem is conceptualized in Figure 5 where CO\(_2\) flows through the injection reservoir. After some period of time the CO\(_2\) plume intersects a finite length fault zone which allows CO\(_2\) to flow
into the overlying aquifer. Derivation of an approximate analytical expression for the leakage percent begins by combining Darcy’s Law (Equation 1) and the general pressure equation (Equation 2) in order to solve for flow rate in both linear (Equation 3) and radial flow cases (Equation 4) [34]. In these expressions flow potential (Φ) is used to account for both the pressure due to fluid injection in the reservoir and gravity (Equation 5). Equation 5 assumes an incompressible system and constant fluid density.

\[
\bar{u} = -\frac{\rho k}{\mu} \nabla \Phi
\]  

(1)

\[\nabla \cdot (k \nabla \rho \Phi) = 0\]  

(2)

\[q_l = -\frac{kwh\rho \Delta \Phi}{\mu l}\]  

(3)

\[q_{rad} = -\frac{2\pi kh\rho}{\mu} \frac{\Phi_a - \Phi_b}{\ln(r_a / r_b)}\]  

(4)

\[\Phi = \frac{p}{\rho} + g\zeta\]  

(5)

Using Equations 3 and 4 it is possible to quantify the flow rate for the reservoir (\(q_r\)) (Equation 6), flow rate through the fault (\(q_f\)) (Equation 7) and flow rate in the overlying aquifer (\(q_a\)) (Equation 8).

\[q_r = \frac{2\pi k_i h_i \rho}{\mu} \frac{\Phi_a - \Phi_b}{\ln(r_{br} / r_a)}\]  

(6)

\[q_f = -\frac{k_f f_w f_i \rho}{\mu h_c} (\Phi_a - \Phi_f)\]  

(7)

\[q_a = \frac{2\pi k_i h_i \rho}{\mu} \frac{\Phi_f - \Phi_b}{\ln(r_{ba} / r_a) / r_f}\]  

(8)

The pressures resulting from fluid injection in the reservoir are shown in the schematic given in Figure 6. The flow potential at the base of the fault is given by \(\Phi_a\), the flow potential at the top of the fault is given by \(\Phi_b\), and the pressure boundary (where there is no pressure build up in the reservoir or aquifer is given by \(p_b\)). The radius of influence of the pressure response due to injection in the reservoir is \(r_{br}\), the radius of influence in the aquifer is \(r_{ba}\). In an infinite acting reservoir the extent of the pressure response can be estimated using the Theis solution (Equation 9) and will be different in the reservoir and aquifer if the permeability values are different.

\[p_b = p_i + \frac{q \mu}{4\pi k_i h_r} W(u)\]  

(9)

The well function \((W(u))\) from the Theis solution can be approximated by Equation 10.
\[ W(u) = -0.5772 - \ln \left( \frac{\phi \mu c r_b^2}{4k_r t} \right) \quad (10) \]

The radius of influence can then be approximated by setting the well function equal to zero and solving for \( r_{br} \) (Equation 11). The radius of influence in the aquifer \( (r_{ba}) \) can be determined by replacing reservoir permeability \( (k_r) \) with aquifer permeability \( (k_a) \) in Equation 11.

\[ r_{br} \approx \frac{2k_r t}{\phi \mu c_l} \quad (11) \]

In order to compare the analytical solution to the simulation results, in which there is a constant pressure boundary (i.e. large volume factor: \( 10^{50} \)), the radius of influence is set to the simulation model half-length of 2500 meters.

Figure 5: Schematic of system with leakage of CO\(_2\) from the injection reservoir to an overlying aquifer with fluid migration through a fault zone. Note that dimensions are not to scale.

Figure 6: Schematic of pressure footprint in the injection reservoir and overlying aquifer when the two units are hydraulically connected. Note that dimensions are not to scale.
Using this conceptual approach, the injected fluid partitions itself into two flow paths, one that stays in the reservoir and one that travels up the fault and then moves radially away from the fault in the upper aquifer. In order to solve for flow in series in the fault and aquifer, three key assumptions are made. First, the flow potential difference between the bottom of the fault and the system boundary in the aquifer is equal to the sum of the flow potential difference between the bottom of the fault ($\Phi_a$) and the top of the fault ($\Phi_f$), and the top of the fault and the system boundary ($\Phi_b$) (Equation 12). This assumption implies that the system has approximately reached steady state which is a good approximation after a long period of constant injection and nearly constant CO2 leakage into the aquifer. Second, the flow rate through the fault is equal to the flow rate into the aquifer (Equation 13). This assumes the fluid and rock in the fault is incompressible. Third, the radius of the fault ($r_f$) can be approximated with a fault area balance equation. In Equation 14 and 15 the radius of the fault is determined such that the area of the circle defined by $r_f$ is equal to the rectangular area of the fault in the simulation model (i.e. the product of the fault width and the fault length). This also implies radial flow in the aquifer, which is a good approximation when the fault length is small relative to the size of the leakage plume in the overlying aquifer.

\[
(\Phi_a - \Phi_b) = (\Phi_a - \Phi_f) + (\Phi_f - \Phi_b)
\] (12)

\[
q_f = q_a
\] (13)

\[
\pi r_f^2 = f_w f_L
\] (14)

\[
r_f = \sqrt{\frac{f_w f_L}{\pi}}
\] (15)

With these assumptions, the fault and aquifer flow equations can be solved for flow potentials and combined into Equation 12.

\[
(\Phi_a - \Phi_b) = \frac{q_a \mu h_c}{k_{f_c} f_w f_L \rho} + \frac{q_a \mu}{2\pi k_a h_a \rho} \ln\left(\frac{r_{ba} - r_a}{r_f}\right)
\] (16)

Next, the reservoir flow rate (Equation 6) is solved for flow potential and combined with Equation 16.

\[
\frac{q_r \mu}{2\pi k_r h_r \rho} \ln\left(\frac{r_{br}}{r_a}\right) = \frac{q_a \mu h_c}{k_{f_c} f_w f_L \rho} + \frac{q_a \mu}{2\pi k_a h_a \rho} \ln\left(\frac{r_{ba} - r_a}{r_f}\right)
\] (17)

Solving for $q_a$ and canceling out viscosity and density gives Equation 18.

\[
q_a = \frac{q_r}{2\pi k_r h_r} \ln\left(\frac{r_{br}}{r_a}\right) \left[\frac{h_c}{k_{f_c} f_w f_L} + \left(\frac{r_{ba} - r_a}{r_f}\right) \frac{2\pi k_a h_a}{2\pi k_a h_a}\right]
\] (18)

In order to compare this analytical result to the simulation results, we use the expression for leakage fraction ($L$), given in Equation 19. The complete solution for the leakage fraction is given in Equation 20.

\[
L = \frac{q_a}{q_a + q_r}
\] (19)
A comparison of the approximate analytical solution with the simulation results for a number of different system geometries (indicated by different colored dots) is shown in Figure 7, and a selection of data points are listed in Table 2. Figure 7 highlights that the agreement between the analytical solution and numerical simulations are best when leakage rates are less than 10%. This is verified quantitatively by calculating the regression coefficients (i.e. $R^2$) for different ranges of leakage values. For the leakage fractions between 0 and 0.3 the regression coefficient is 0.714, whereas for leakage fractions between 0 and 0.1 the regression coefficient is 0.906. At higher leak rates, when large quantities of CO$_2$ leak into the overlying aquifer, the radial nature of flow in the storage reservoir breaks down and thus violates the radial flow assumptions. The solution also is more accurate when the fault length is shorter. The model geometry that produces leakage that is most accurately predicted analytically is the model with a fault zone located 500 meters from the injection well and a fault length of only 100 m (green dots in Figure 7). This is because the radial flow assumption in the aquifer is violated as fault length increases, creating a more elongated leakage plume.

These results highlight the risk of injecting into low permeability reservoirs with high permeability overlying aquifers. From Table 2 it can be seen that even relatively low permeability faults have the potential to experience significant leakage when a high permeability aquifer overlies the injection reservoir. Alternatively, if the overlying aquifer has a low permeability then regardless of the fault permeability the leakage fraction never gets higher than a few percent.

Table 2: Comparison of semi-analytical solution and simulation results for a number of key system permeability values. All values are from the case with a 500 m long fault zone 500 m from the injection well.

| Reservoir Permeability (mD) | Aquifer Permeability (mD) | Fault Permeability (mD) | Semi-Analytical Leakage Percent | Simulation Leakage Percent |
|-----------------------------|---------------------------|-------------------------|---------------------------------|---------------------------|
| 28                          | 28                        | 1000                    | 9.43                            | 13.6                      |
| 28                          | 28                        | 10                      | 5.13                            | 4.48                      |
| 28                          | 2.8                       | 1000                    | 1.04                            | 1.5                       |
| 28                          | 2.8                       | 10                      | 0.64                            | 0.49                      |
| 280                         | 2.8                       | 100                     | 0.10                            | 0.3                       |
| 280                         | 2.8                       | 10                      | 0.099                           | 0.19                      |
| 280                         | 280                       | 1                       | 6.07                            | 4.9                       |
| 2.8                         | 280                       | 1                       | 14.2                            | 9.4                       |
| 2.8                         | 28                        | 100                     | 49.6                            | 33.6                      |
| 2.8                         | 28                        | 10                      | 39.2                            | 25.9                      |
| 2.8                         | 28                        | 1                       | 12.7                            | 8.6                       |

It is important to note that this solution works relatively well without incorporating multiphase fluid flow properties because in much of this system, the mobility ratio is near one. Based on relative permeability characteristic curves, the relative permeability of CO$_2$ is around 0.1 for water saturations between 0.5 and 0.7; the typical water saturation throughout much of the CO$_2$ plume away from the injection well. The reduction in permeability is then offset by the viscosity of CO$_2$, which is almost an order of magnitude lower than water at reservoir conditions. This results in a mobility ratio of 0.9 for an average water saturation of 0.55.
5. Conclusion

Assuring CO₂ storage security is essential for the widespread implementation of carbon capture and sequestration. Appraising the potential for leakage through faults in seals is an important component of site screening, assessment and selection. The risk of leakage can be reduced by developing a better understanding of the behavior of CO₂ leakage through a fractured caprock. Using a detailed sensitivity analysis, this study identified the importance of the reservoir, overlying aquifer, and fault permeabilities on the risk of leakage. Of these factors, reservoir permeability was found to be the most important factor. This may seem counter intuitive, as the fault permeability may be assumed to be the most important factor in determining leakage. However, if reservoir permeability is very high, then any flow path must be higher than this permeability in order to be a pathway for significant CO₂ leakage. As the injection reservoir permeability gets lower, the chance of encountering faults with proportionally higher permeability becomes more likely. Lower reservoir permeability results in a higher pressure build up in the reservoir, increasing the driving force for leakage. Further work is necessary to understand the multiphase flow behavior of faults and fractures, especially the capillary pressure.

After the most important characteristics controlling CO₂ leakage from storage reservoirs were identified a simple approximate semi-analytical solution was derived that relies on these characteristics to estimate the fraction of the injected CO₂ that could leak into the overlying aquifer. The analytical expression agrees well with the simulation results at leakage rates less than 10% of the total CO₂ injected. At higher leakage rates several of the assumptions of the system begin to break down and the solution becomes less accurate at prediction leakage values. Results from this work can be used by operators and regulators to quickly assess the risk of a particular storage site based only on overlying aquifer and injection reservoir flow characteristics and geometry. Areas identified as higher risks could be reevaluated or require additional monitoring and verification in order to assure the long term storage security of sequestered CO₂.

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