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Delineating area of review in a system with pre-injection relative overpressure

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Abstract

The Class VI permit application for geologic carbon sequestration (GCS) requires delineation of an area of review (AoR), defined as the region surrounding the (GCS) project where underground sources of drinking water (USDWs) may be endangered. The methods for estimating AoR under the Class VI regulation were developed assuming that GCS reservoirs would be in hydrostatic equilibrium with overlying aquifers. Here we develop and apply an approach to estimating AoR for sites with pre-injection relative overpressure for which standard AoR estimation methods produces an infinite AoR. The approach we take is to compare brine leakage through a hypothetical open flow path in the base-case scenario (no-injection) to the incrementally larger leakage that would occur in the CO_2-injection case. To estimate AoR by this method, we used semi-analytical solutions to single-phase flow equations to model reservoir pressurization and flow up (single) leaky wells located at progressively greater distances from the injection well. We found that the incrementally larger flow rates for hypothetical leaky wells located 6 km and 4 km from the injection well are ~20% and 30% greater, respectively, than hypothetical baseline leakage rates. If total brine leakage is considered, the results depend strongly on how the incremental increase in total leakage is calculated, varying from a few percent to up to 40% greater (at most at early time) than base-case total leakage.

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Keywords: Area of Review, Class VI, overpressure, underpressure, hydrostatic pressure, USDW

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1. Introduction

The U.S. EPA Class VI permit application for geologic carbon sequestration requires delineation of an area of review (AoR), defined as the region surrounding the geologic carbon sequestration (GCS) project where underground sources of drinking water (USDWs) may be endangered by the injection activity [1]. Briefly, the AoR is the area within which CO_2 or saline water, or both, could migrate upwards through hypothetical open flow paths (e.g., undetected leaky wells) to shallower aquifers containing USDW under the driving force of increased pressure arising from the CO_2 injection. The original methods for estimating AoR under the Class VI regulation were developed assuming that geologic storage reservoirs would be in hydrostatic equilibrium (including effects of density variations due to salinity and temperature) with overlying aquifers containing USDW.

It happens that some deep brine formations targeted for GCS are not in hydrostatic equilibrium. For example, underpressure can be caused by erosion and melting of continental ice [2], overpressure by crustal loading due to a high sedimentation rate [3], and either over- or underpressure can be caused by fluid production or injection in different strata separated by low-permeability formations. For cases where aquifers are isolated by cap-rock seals, these anomalous pressures can persist over geologic time and present challenges for managing and regulating fluid injection and production.

We present in Figure 1 a sketch of pressure profiles with depth for a system consisting of a deep injection zone, a cap rock of thickness h_{cap}, and an overlying aquifer containing USDW protected by U.S. EPA Class VI regulation. As shown for this example case, the pressure in the USDW (P_u) is drawn down (lowered) from the hydrostatic profile, e.g., by prior fluid production somewhere (not shown) in the USDW aquifer. We assume in this case that the initial pressure in the injection zone ($P_{i,0}$) is also drawn down (e.g., by prior fluid production), but not by as much as the overlying aquifer resulting in a pre-injection relative overpressure situation. For this case, upward flow would occur through the hypothetical open flow path across the cap rock sketched in the figure even in the absence of an injection process. Application of the standard Class VI AoR delineation approach in this case would result in an infinite AoR because USDW would be considered endangered at any radius away from the injection well.

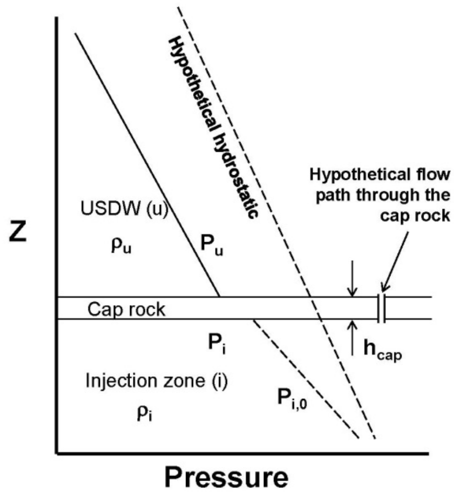

Fig. 1. Underpressured system with relative overpressure in the injection zone.

The U.S. EPA presented some possible approaches to calculating AoR for the case of pre-injection relative overpressure in its updated guidance document [1, p. 42]. The approaches suggested can be summarized as follows:

1) Calculations can be carried out of the overpressure that can be sustained without resulting in upward fluid flow (no leakage) due to the greater density of the fluid rising upward from the injection zone in the hypothetical flow path;
2) Modeling may be carried out to show that additional pressure increases up to a certain point within an already over-pressurized injection zone may not cause an appreciable increase in fluid leakage rates through a hypothetical borehole. A sensitivity analysis may be conducted to bound the modeled leakage rates.
3) Modeling may be carried out to estimate how additional fluid leakage caused by the injection project is diluted within the USDW and attenuated, e.g., by the natural background flow rate of water within the USDW, to a degree that negligible degradation would occur.

In this study, we develop and demonstrate an approach inspired by (2) and illustrated in Figure 2. As shown in Figure 2a, the incremental increase in flow rate up a hypothetical conduit under an injection scenario for the case of pre-injection relative overpressure is a function of time and the distance of the leaky well (radius) away from the injection well. At infinite radius, the flow rate would be constant with time assuming the conduit is very small and the volume of the injection zone is very large. On the other hand close to the injection well, or near the CO_2 plume front where pressure rise due to injection is very large, the flow rate through a hypothetical conduit would be correspondingly larger. At some radius between zero and infinity, there is a location at which the incrementally larger flow rate up the hypothetical conduit due to CO_2 injection would be acceptably small. This is illustrated schematically in Figure 2b.

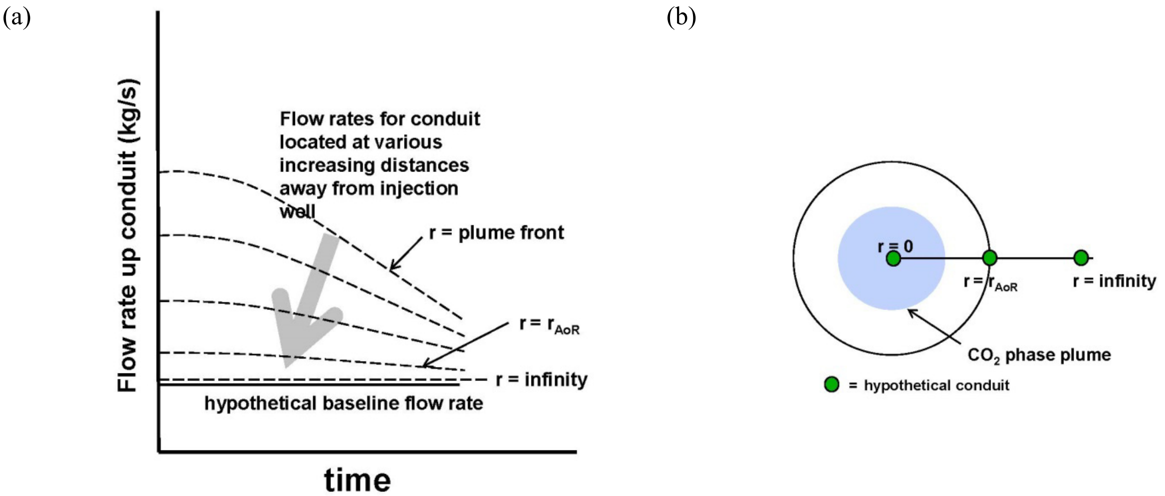

Fig. 2. (a) Schematic of flow rate up hypothetical conduit versus time for conduits located at various distances from the injection well. (b) Plan view of CO_2 phase plume and three hypothetical open conduits at various distances (r) from the injection location at $r = 0$. In Fig. 2b, r_{AoR} = radius of the location of a hypothetical conduit through which the incrementally larger flow rate of brine arising from injection of CO_2 would be acceptably small relative to the flow rate of brine rising through the same hypothetical conduit under existing (no-injection) conditions.

In this study, we demonstrate this approach through the application of semi-analytical solutions for flow up a single leaky well positioned at a range of locations away from the injection well. By comparing flow rates up leaky wells at different distances from the injection well, we find a distance away from the injection well at which the incremental increase in flow rate is acceptable. Interestingly, the choice of how to compare injection-related total leakage to the no-injection-related total leakage case (base case) turns out to be an outstanding question. Furthermore, the discussion here highlights the incongruity between the assumption of a hypothetical open flow path and the presence of pre-injection relative overpressure.

2. Approach

To estimate AoR for systems with pre-injection relative overpressure, we carried out modeling using semi-analytical solutions for brine pressurization and related single-phase flow up (single) leaky wells located at progressively greater distances from the injection well. From these results, we evaluate the radial decrease in upward flow rates generated by injection at locations farther and farther from the injection well. The calculations are for brine flow rather than CO_2 flow up the hypothetical leaky well because the AoR is assumed to be controlled by the pressure front which normally extends much farther from the injection well than the CO_2-phase front.

Earlier studies (e.g., [4, 5]) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably well described by a single-phase flow calculation—without the need to account for two-phase flow effects— simply by representing CO_2 injection as an equivalent-volume injection of brine. As our focus is on pressure changes and brine leakage at the far-field zones outside of the expected CO_2 plume zone, we have made the same assumption in this study. We consider the conceptual model shown in Figure 3 for evaluating brine leakage through leaky wells. We employ a previously developed analytical solution [6] for flow of a single-phase fluid in a multi-layered aquifer system comprising an arbitrary number of aquifers with alternating aquicludes or aquitards and any number of injection/extraction wells and leaky wells. While all aquifers and aquitards are assumed homogeneous, with uniform thickness and infinite extent, each aquifer and aquitard may have different thicknesses and hydraulic properties. Leaky wells are represented as Darcy-type flow pathways with segment-wise property variation (e.g., well radii, permeability, screened/cased in well-aquifer segments, plugged/unplugged in well-aquitard segments), where segments correspond to intersections of each well with layers of the multilayered system. The equations of horizontal groundwater flow in the aquifers are coupled by the vertical-flow equations in the aquitards and the flow-continuity equations in the leaky wells (Note that vertical groundwater flow equations are omitted if the aquitards are impermeable.) The governing partial differential equations for single-phase flow in aquifers and aquitards are transformed into the Laplace domain, and the resulting coupled system of ordinary differential equations (ODE) are solved using the eigenvalue analysis method. The generalized solution for hydraulic head buildup or drawdown in the Laplace domain for a system of N aquifers, N_I injection wells, and N_L leaky wells is developed using the superposition principle. The Stehfest numerical Laplace inversion method [7, 8] is applied to convert the solutions obtained in the Laplace domain into the real-time domain. Readers are referred to [6] for further details of the solution method and description of a FORTRAN program developed for computing the general solution. We used the focused-leakage feature (impermeable aquitards) of the developed program to solve the problem depicted in Figure 3. The original model and the program assumed initially hydrostatic pressure distributions in the entire system. For this work, we have made slight changes in the program to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers, i.e., pre-injection relative overpressure.

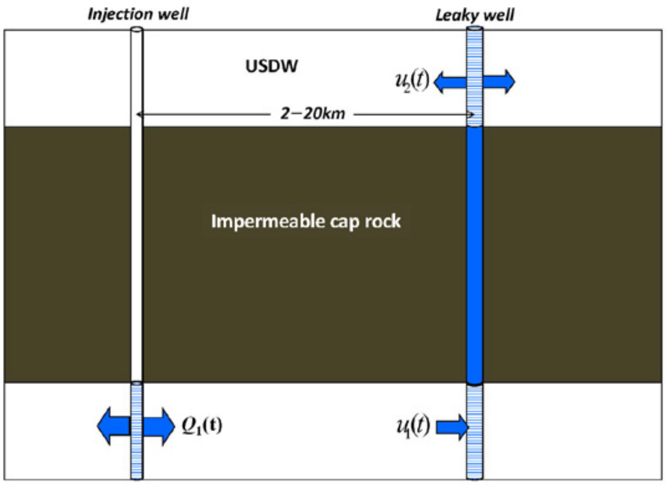

Fig. 3. Sketch of conceptual model for injection and pressurization of the injection zone leading to brine leakage up a leaky well into USDW.

3. Results

Brine leakage over time was calculated for brine flow up a single hypothetical leaky well located at 2, 4, 6, 8, 10, 15 and 20 km distances away from an injection well for the case in which CO_2 injection lasts for four years. The properties of the system approximate those of a low-permeability mid-continent U.S. CO_2 storage project and are provided in Table 1. Briefly, the storage reservoir (injection zone) is approximately 1.2 km deep with permeability of 30 mD and contains saline water of density 1090.55 kg/m^3, while the USDW aquifer is 186 m shallower (i.e., cap rock is 186 m thick), has permeability of 30 mD, and contains water with density 1002.77 kg/m^3. The injection rate is specified as 835.32 m^3 H_2O/d which corresponds to 7.92 kg CO_2/s (assuming CO_2 density of 819.3 kg/m^3 at reservoir pressure and temperature conditions).

Table 1. System properties for semi-analytical calculations of leakage up a leaky well.

Property	Storage Reservoir	USDW aquifer
Thickness	50 m	50 m
Average Initial Head	1036.4 (m)	817.35 (m)
Density*	1090.55 (kg/m^3)	1002.77(kg/m^3)
Viscosity*	9.30×10^{-4} (Pa.s)	9.26×10^{-4} (Pa.s)
Salt mass fraction	0.13	0.0035
Temperature	34.7 (Celsius)	23.3 (Celsius)
Brine compressibility*	3.45×10^{-10} (Pa^{-1})	4.46×10^{-10} (Pa^{-1})
Pore compressibility	1.63×10^{-9} (Pa^{-1})	1.63×10^{-9} (Pa^{-1})
Permeability	30 mD	30 mD
Porosity	0.1	0.1
Specific Storativity	2.11×10^{-6} (1/m)	2.04×10^{-6} (1/m)
Injection well radius	0.15 m	0.15 m
Injection rate	835.32 m^3/d	0
Leaky well radius	0.15 m	0.15 m
Leaky well permeability	10^{-7} m^2	10^{-7} m^2

Results are plotted as leakage rate (m^3/d) and ratio of leakage rate for injection-related leakage to the leakage rate for the no-injection case as a function of time (yr) in Figure 4. As shown, the system leaks brine for 50 yrs prior to the beginning of injection, at which point the leakage is enhanced by the injection, especially for a leaky well located near (e.g., 2 km) the injection well. The enhancement of leakage persists long after the injection stops after four years. For a leaky well located farther from the injection well, e.g., greater than 10 km, the leakage rate is only slightly enhanced following injection. The leakage rate is enhanced by 50-60% at 2 km from the injection well, and by about 10% 10 km from the well. These curves illustrate the fundamental result that injection causes pressure increases in the injection zone that are highest near the injection well. This incrementally larger pressure drives brine leakage up the hypothetical leaky well. But it is important to note that because of pre-injection relative overpressure, there is always a background brine-leakage driving force that causes brine leakage up any well before injection starts and throughout the injection and post-injection periods. The overall decline in the background leakage rate from t = 0 to t = 100 yrs reflects the decline in pressure that arises from the leakage up the leaky well.

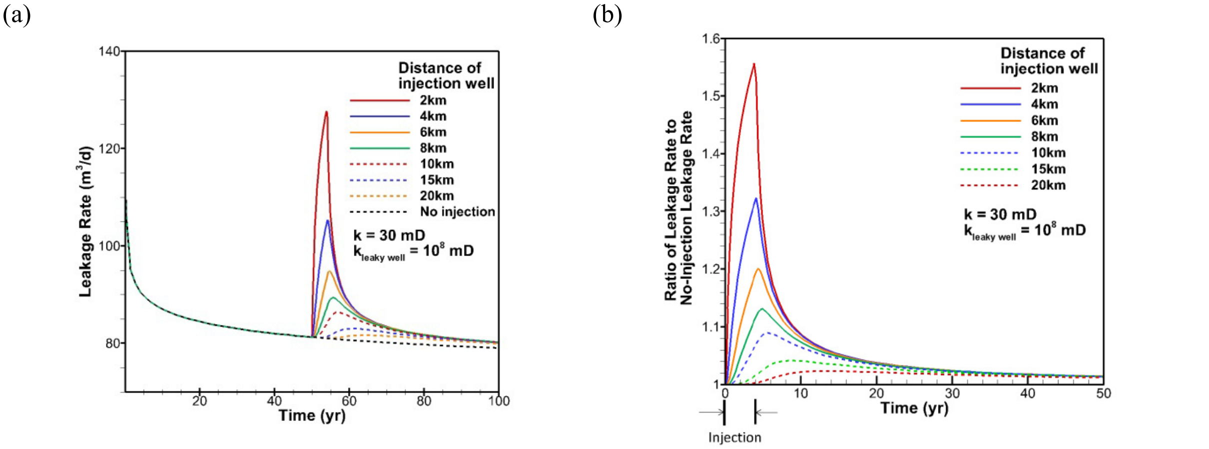

Fig. 4. (a) Leakage rates of brine up hypothetical leaky wells at various distances from the injection well for the case in which CO_2 injection starts at 50 years and lasts for four years. (b) Ratio of injection-related leakage rate to no-injection leakage rate.

In order to estimate an AoR under U.S. EPA Class VI regulations, we need to evaluate the ratio or fractional increment in leakage that occurs due to the injection project. Figure 4b shows that the ratio of leakage rates is one way of evaluating this. But leakage rate does not provide an overall indication of long-term total impact to USDW which is the basis for Class VI regulations. For this, evaluation of incremental total cumulative leakage is preferable. To calculate such an incremental increase, we need to assume a background, or no-injection scenario, against which we can compare the injection scenario in terms of the ratio of cumulative leakage with injection project normalized by cumulative leakage in the no-injection scenario case. Two obvious options present themselves to accomplish the normalization, referred to as Normalization Method 1, and Normalization Method 2. In Normalization Method 1, we divide the CO_2-injection cumulative leakage (m^3) at each well by the cumulative leakage that has occurred starting at t = 0 (50 yrs before injection started) until the time of interest. In Normalization Method 2, we divide the CO_2-injection case cumulative leakage (m^3) at each well by the cumulative leakage that has occurred starting at t = 50 yrs (start of injection) until the time of interest.

We show in Figure 5 the results of cumulative incremental leakage using each of the normalization options. As shown in Figure 5a, Normalization Method 1 results in overall incremental increases on the order of 1-5%. We note further that the maximum in incrementally larger fluid leakage occurs after the injection has stopped for all distances plotted. This lack of maxima in the curves occurs because the baseline cumulative leakage volume is large but diminishing over the decades, and its position in the denominator means that the ratio will tend to increase unless the change in the injection-induced flow decreases faster as is the case for leaky wells located nearer to the injection well. In general, Normalization Method 1 produces apparently small incremental leakage flow because the normalization involves large background leakage.

Figure 5b shows the same results using Normalization Method 2, whereby the cumulative leakage volume is normalized by the total leakage starting at the time of injection. This normalization does not contain the large 50-yr-pre-injection leakage volume that was included in Normalization Method 1, and therefore results in larger apparent incremental leakage (10-40% versus 1-5%), even though the absolute leakage is the same for both cases. Furthermore, the character of the rise and fall of the incrementally larger leakage is quite different for Normalization Method 2, which reflects much more closely the actual injection period and the cessation of injection. Nevertheless, the maximum in the ratio occurs after the injection has stopped at distances greater than about 6 km from the injection well. The reason for this behavior is that the cessation of injection does not reduce pressure, but rather halts the continued increase in pressure.

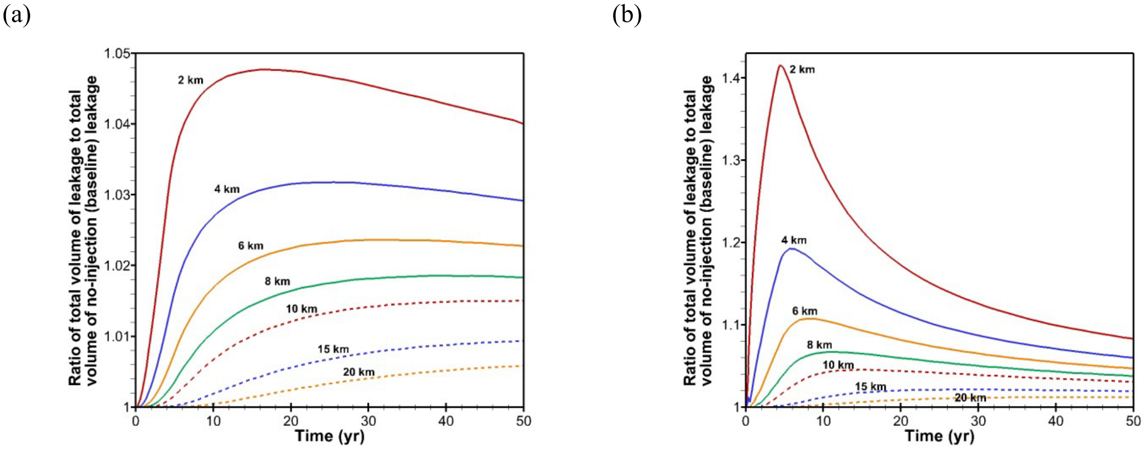

Fig. 5. (a) Ratio of total volume of leakage to total volume of no-injection case leakage including 50 yrs of pre-injection leakage (Normalization Method 1) for four years of injection starting at $t = 0$ yrs. (b) Ratio of total volume of leakage to total volume of no-injection case leakage (Normalization Method 2) for four years of injection starting at $t = 0$ yrs.

4. Discussion

The results above show clearly the importance of normalization method in evaluating how much more (the increment) brine leakage occurs for the case of an injection project relative to the natural (no-injection project) base case. We chose 50 years of natural background pre-injection leakage for our Normalization Method 1, and zero years for Normalization Method 2. Clearly the longer you choose this period to be, the smaller the apparent incremental increase will be for the injection case.

The reason that this question of how long a time period prior to injection one should consider comes up is that the two features, pre-injection relative overpressure and an open flow path, are incongruous. Simply put, if an open flow path existed for geologic time, there would be no pre-injection relative overpressure. So the only physically plausible scenario includes pre-injection flow up the open flow conduit, leaving us to decide how long this flow has been occurring prior to injection, and to include this relative volume in the comparison of natural background brine leakage to injection-related leakage.

5. Conclusions

We find that the incrementally larger flow rates for hypothetical leaky wells located 6 km and 4 km from the injection well for the parameters and properties considered here are at most ~20% and 30% greater, respectively, than hypothetical baseline leakage rates. If total brine leakage is considered, and depending on how incremental total leakage is calculated, we find that the apparent incremental total leakage can be either a few percent or up to 40% greater (at most at early time) than baseline total leakage. We emphasize that the actual leakage is the same regardless of how we calculate the incrementally larger leakage. Open questions remain about what would be considered an acceptably larger incremental increase in leakage for the purposes of delineating AoR, and what the appropriate way to compare the incremental leakage should be. We note finally that the approach presented here will also apply to a set of injection wells rather than a single well if the hypothetical leaky wells are located far from the injection wells.

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