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Geologic carbon sequestration injection wells in overpressured storage reservoirs: estimating area of review

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Abstract

The Area of Review (AoR) under the US Environmental Protection Agency's (EPA) Class VI CO_2 injection permit is defined as the region surrounding the geologic carbon sequestration (GCS) project where underground sources of drinking water (USDWs) may be endangered. Estimation of the AoR is based on the calculated reservoir pressurization due to CO_2 injection and the associated potential to lift saline water into potable groundwater aquifers through open flow paths (e.g. wells) assuming the system is hydrostatic. In cases where the storage reservoirs are not initially hydrostatic, and in particular where they are overpressured, AoR estimation methods need to be altered. In this paper, we present and apply an approach to evaluating potential endangerment of USDW based on comparing brine leakage through a hypothetical open flow path in a no-injection scenario and brine leakage in a CO_2-injection scenario. We present six possible ways to normalize injection-related leakage relative to no-injection leakage. We calculate leakage using semi-analytical solutions for single-phase flow and model reservoir pressurization and flow up (single) leaky wells located progressively farther from the injection well. For an example case of relative overpressure and using an injection-rate-based approach, results show 50–60% larger open-well-leakage rates for wells located at 2 km and 10% increase for wells located at 10 km from the injection well relative to the no-injection case. If total brine leakage is considered, the results depend strongly on the assumed pre-injection to post-injection time frames and on the methods of normalization used to calculate incremental leakage.

Introduction

Injection of carbon dioxide (CO_2) for geologic carbon sequestration (GCS) causes an increase in pressure in the injection zone. If permeable flow paths exist between the injection zone and underground sources of drinking water (USDW), saline water may be driven upward into potable aquifers. Recognizing this hazard, the US Environmental Protection Agency (EPA) Class VI permit application for geologic carbon sequestration (GCS) requires estimation of an area of review (AoR), defined as the region surrounding the GCS project where underground sources of drinking water (USDWs) may be endangered by the injection activity.[1] 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.

AoR estimation methods under the Class VI regulation were developed assuming that geologic storage reservoirs would be in hydrostatic equilibrium with overlying aquifers containing USDW. It happens that some deep brine formations targeted for GCS are not in hydrostatic equilibrium. The overpressure situation can develop from natural processes such as erosion or by melting of continental ice, both of which change the thickness of the overburden under which previously open aquifers may have equilibrated but are now isolated.[2] Overpressure of isolated aquifers can also be caused by the natural process of crustal loading due to a high sedimentation rate.[3] There are also anthropogenic causes, for example, either overpressure or underpressure can be caused by fluid production or injection in different aquifers separated by low-permeability aquitards. By virtue of their longevity, naturally overpressured reservoirs reflect the very low permeability of surrounding formations which would otherwise provide a pressure-equilibrating sink for groundwater. Manmade overpressure may or may not be so long-lived, depending on the degree of isolation of the affected aquifer. For cases where aquifers are isolated by cap-rock seals or very low-permeability formations, anomalous pressures can persist over very long times and present challenges for managing and regulating fluid injection and production.

Schematic pressure profiles are shown in Fig. 1 for a system with a deep injection zone, a cap rock of thickness h_{cap}, and an overlying aquifer containing USDW which is protected by US EPA Class VI regulation.[1] The pressure profiles as drawn assume that pressure variation within USDW and the injection zone are hydrostatic, i.e., at static equilibrium controlled by local groundwater (brine) density. The pressure in USDW (P_u) is drawn down (lowered) from the hydrostatic profile, for example by prior fluid production somewhere (not shown) in the USDW aquifer. In the case sketched in the figure, 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. As shown in the sketch, upward flow would occur through the hypothetical open flow path across the cap rock even in the absence of CO_2 injection that would cause more overpressure. Application of the standard Class VI AoR delineation approach in this case would result in an infinite AoR because the USDW would be considered endangered at any radius away from the injection well, and in fact, before any CO_2 has been injected.

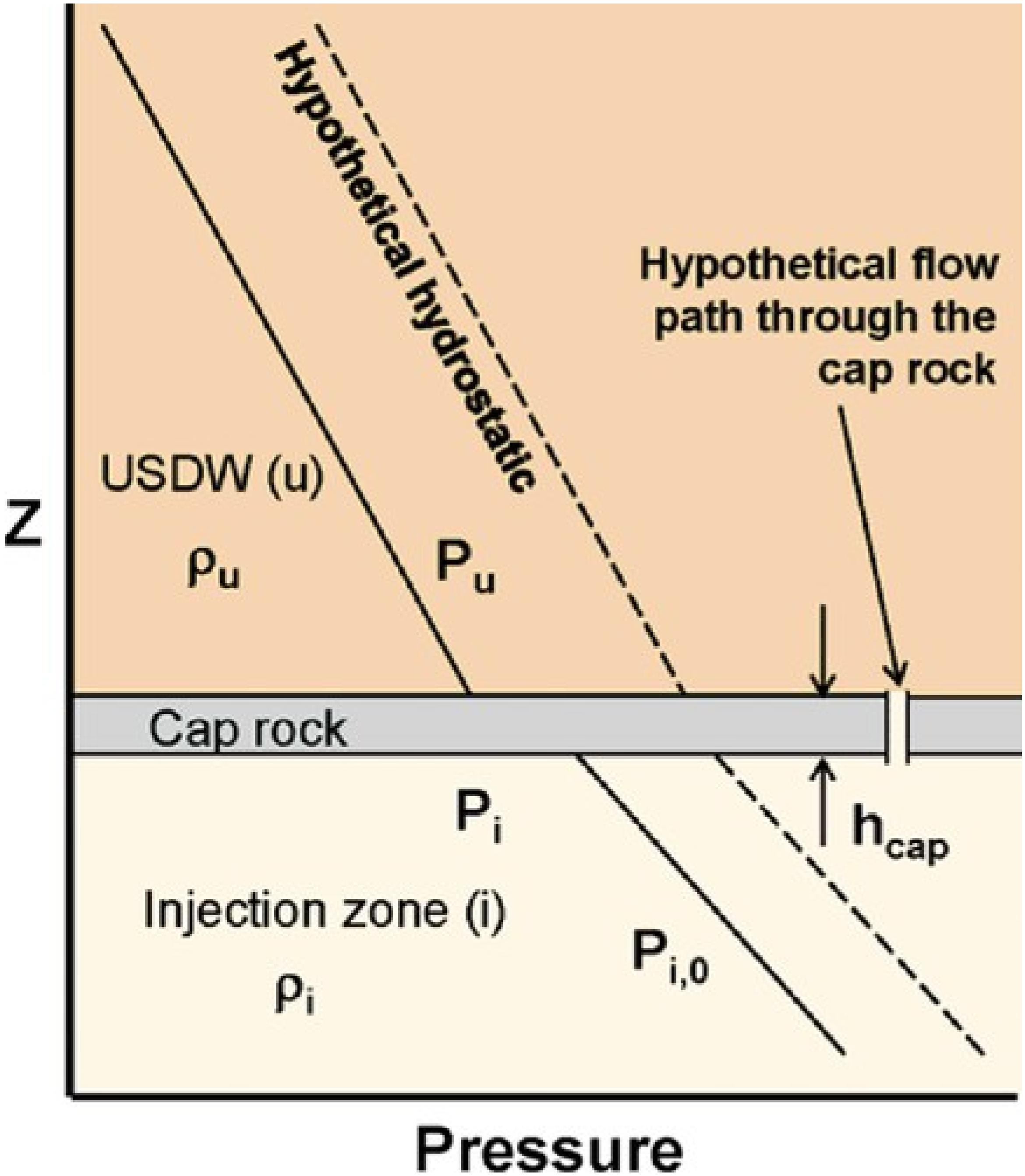

Figure 1

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Underpressured USDW (P_u) with relative overpressure ($P_{i,0}$) in the injection zone.

Caption

The US EPA published an updated guidance document which included possible methods to calculate AoR for the case of pre-injection relative overpressure.4 The methods 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 overpressurized 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, for example, by the natural background flow rate of water within the USDW, to a degree that negligible degradation would occur.

Method 1 acknowledges that upward displacement of fluid with larger density than fluid at any elevation during ascent requires a degree of overpressure that does not contribute directly to upward fluid flow. In such systems, the allowable pressurization of the reservoir can be larger for a given AoR. We note that density of formation water is affected by both salinity and temperature, and that upward-displaced brines will cool and become even denser requiring greater overpressure to sustain their rise.5 Nevertheless, the cases of interest here are those for which the relative overpressure is much larger than would be compensated by density contrast alone.

Method 3 acknowledges that flow and mixing within the USDW aquifer may dilute brine leakage occurring at distal regions of the pressurized GCS project footprint to such a degree that no substantive degradation occurs, in which case such leakage could be allowed. Method 3 also implicitly involves consideration of the groundwater compositions, for example total dissolved solids (TDS), in the storage reservoir and the USDW aquifer. If the USDW is just below the 10 000 ppm TDS limit and the storage reservoir brine is just above 10 000 ppm TDS, the amount of degradation of the USDW arising from upward brine migration might be arguably different from that arising from mixing of dense brine from the storage reservoir with a low-TDS USDW above. Regardless of the details of composition, as the hypothetical leakage increases closer to the injection well, there would come a point where flow and mixing may not mitigate the brine leakage, a point which could potentially be used to define the extent of the AoR. Method 3 provides a potential opening for modeling and analysis to be used to predict the evolution of groundwater composition in the USDW aquifer arising from hypothetical upward leakage from the storage reservoir over time.

In contrast to Method 3, the standard approach to estimating AoR (for normally pressured systems) emphasizes the flow of brine into the USDW rather than degree of impact on composition of the USDW. Consistent with the emphasis on flow embodied in the standard approach, we develop and demonstrate here an approach suggested by Method 2 to address the situation of relative overpressure that we believe may be more common than initially assumed by the Class VI regulation. As shown in Fig. 2(a), the working conceptual model includes an incremental increase in flow rate up a hypothetical conduit following CO_2 injection for the case of pre-injection relative overpressure. This increase will be a function of time and the distance of the leaky well away from the injection well. At infinite distance, the flow rate would be at steady-state 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 and variable with time depending on the injection schedule. 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 Fig. 2(b).

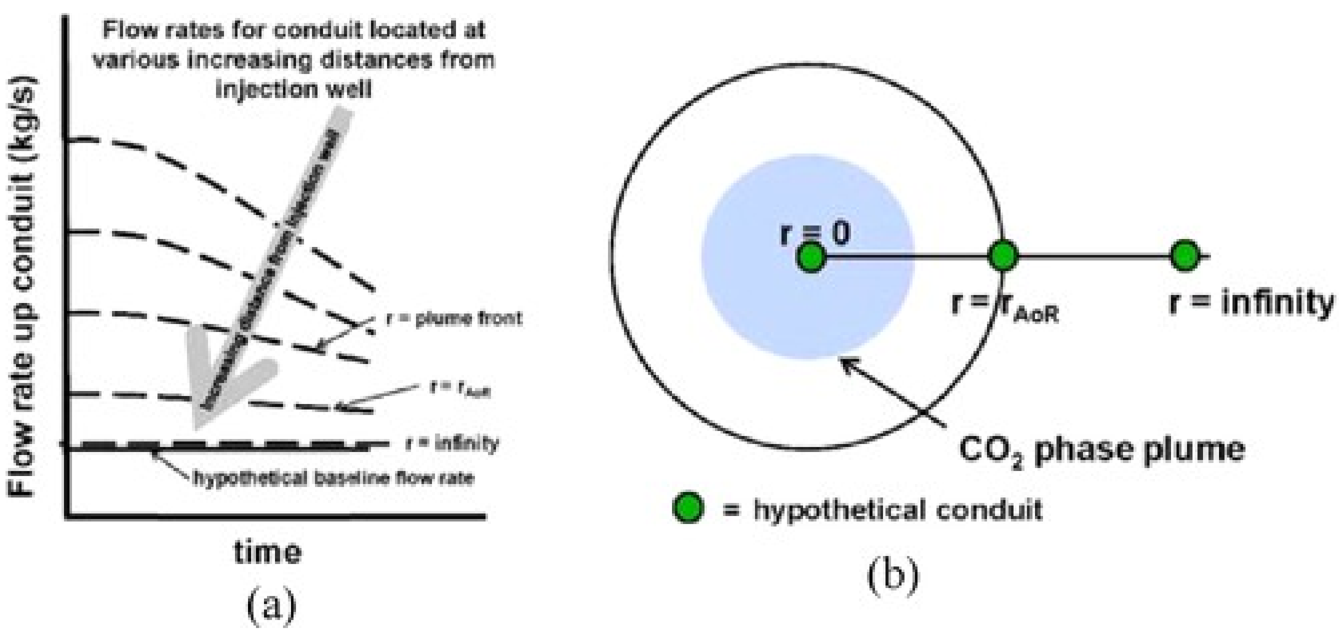

Figure 2
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(a) Schematic of flow rate up a hypothetical conduit versus time after injection stops for the conduit located at various distances (radii) from the injection well. (b) Plan view of CO_2 phase plume and the hypothetical open conduit at three 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 ambient (no-injection) conditions.
Caption

Here 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 and total brine leakage 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 might be acceptable. While this is a single general approach, there is a multitude of ways that the results can be quantified and compared. This paper evaluates six different methods of normalizing the injection versus no-injection leakage and thereby extends our earlier conference proceedings paper in which we evaluated two such methods.[6]

Prior work

Although the AoR concept is broadly used by the US EPA to define the geographic area where existing wells need to be evaluated and/or remediated to avoid potential leakage under the Underground Injection Control (UIC) program in general, here we focus on GCS and the US EPA Class VI requirements for AoR.[1, 4] During and after GCS, leakage of brine upward into USDW is the main concern because of the large area of elevated pressure in the storage reservoir, the vast majority of which has not been invaded by CO_2. An excellent summary of AoR for GCS, along with discussion of preventing leakage in the Texas Gulf Coast region where abandoned wells are common, is given by Nicot *et al*.[7] Other notable GCS-related papers include analyses of density effects that tend to mitigate upward brine leakage.[5, 8, 9] Other studies have been carried out to develop ways of limiting pressure for, among other reasons, reducing the size of the AoR.[10] Recent work has focused on recommendations of new ways of evaluating and remediating wells over very large areas of pressure elevation.[11] Although overpressured reservoirs are the focus of the updated guidance document,[4] we are not aware of any studies on modeling and analysis to investigate estimating AoR for overpressured systems, or for investigating the implications of pre-injection relative overpressure on the estimation of AoR.

Approach

In order to analyze the problem of estimating AoR for systems with pre-injection relative overpressure, we used semi-analytical solutions for brine pressurization and related single-phase flow up individual leaky wells to quantify leakage rates and total amounts over a range of distances from the injection well. Our approach is to locate individual leaky wells at progressively greater distances from the injection well and to calculate the leakage caused by CO_2 injection. These results are then used to evaluate the decrease with increasing distance away from the injection well of upward leakage flow rates (and total amount leaked) due to injection. 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.

Prior studies[12], [13] have shown that pressure changes outside of the CO_2 plume domain can be reasonably well described by single-phase flow calculations – without the need to account for two-phase flow effects – by representing CO_2 injection as an equivalent-volume injection of brine. Because 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.

The conceptual model we consider is shown in Fig. 3. As shown, we consider individual leaky wells (one at a time) at different distances from the injection well. We use the analytical solution previously developed by Cihan *et al*.[14] for flow of a single-phase fluid in a multilayered aquifer system comprising an arbitrary number of aquifers with alternating aquicludes or aquitards and any number of injection/extraction wells and leaky wells. In the method, all aquifers and aquitards are assumed homogeneous, with uniform thickness and infinite extent, although 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 constant-density flow-continuity equations in the leaky wells. In the method, 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) is solved using the eigenvalue analysis method. The generalized solution for hydraulic head build-up or drawdown in the Laplace domain for a system of *N* aquifers, *NI* injection wells, and *NL* leaky wells is developed using the superposition principle. The Stehfest numerical Laplace inversion method[15], [16] is applied to convert the solutions obtained in the Laplace domain into the real-time domain. Readers are referred to Cihan *et al.*14 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 (with impermeable aquitards) of the developed program to solve the problem depicted in Fig. 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, specifically, pre-injection relative overpressure. We note that the method assumes constant-density brine in the leaking well, an assumption that leads to slight over-predictions of leakage because of the density contrast between brine in the storage reservoir and whatever fluid is initially in the leaking well.

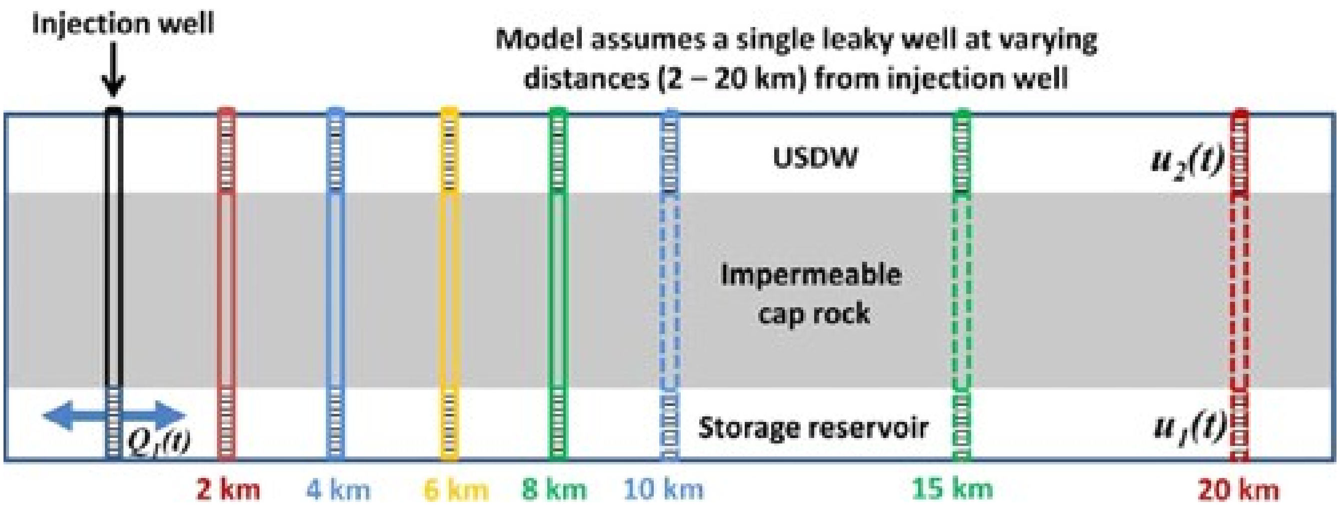

Figure 3

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Sketch of conceptual model for injection and pressurization of the storage reservoir showing a hypothetical open-well leakage pathway at seven locations, only one of which exists for any single calculation. Line patterns and colors correspond to patterns and color of curves in Figs. 4and 5.

Caption

Results

We calculated the temporal evolution of brine leakage for flow up a single hypothetical leaky well located at distances of 2, 4, 6, 8, 10, 15, and 20 km away from the injection well for four years of CO_2 injection corresponding to the duration of injection for a proposed research CO_2storage project. The system we chose has properties consistent with the site of this proposed research CO_2 storage project at a low-permeability mid-continent US site as shown in Table 1. The storage reservoir (injection zone) is approximately 1.2 km deep with permeability of 30 mD and contains saline water of density 1090.6 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). From the initial average pressures and the 186 m separation between USDW and storage reservoir, there is a pre-injection relative overpressure of 2.60 MPa, a value we calculate by subtracting from the reservoir pressure the sum of the USDW pressure and the pressure generated within the hypothetical cap-rock conduit of Fig. 1, if filled with reservoir fluid, i.e., 9.85 MPa – (5.26 MPa + 1090.6 kg/m^3 * 9.81 m/s^2 * 186 m * 10^{-6} MPa/Pa) = 2.60 MPa). This overpressure implies that one would have to reduce the pressure in the storage reservoir by 2.60 MPa to avoid driving brine upward to USDW before any injection has occurred whatsoever. We note that the presence of pre-injection relative overpressure and pre-existing leakage pathways means that (i) any pre-existing leakage pathway would be actively leaking brine into the USDW before any injection begins, and (ii) pre-injection relative overpressure probably could not be sustained over geologic time if hypothetical leaky flow path(s) are present.

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 pressure	9.85 MPa	5.26 MPa
Density*	1090.6 kg/m^3	1002.8 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 ˚C	23.3 ˚C

Property	Storage Reservoir	USDW aquifer
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	2.113×10^{-6} m^{-1}	2.043×10^{-6} m^{-1}
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	10^5 D (10^{-7} m^2)	10^5 D (10^{-7} m^2)

- *Values calculated using correlations.17, 18

Results of leakage calculations are shown in Fig. 4 as leakage rate (m^3/d) versus time (yr), and ratio of leakage rate (for injection-related leakage) to the leakage rate for the no-injection case versus time (yr). The main thing to note in Fig. 4(b) is that leakage occurs prior to the CO_2injection because of the assumption of an existing leakage pathway and the existence of pre-injection relative overpressure. Here we have assumed a pre-injection period of 50 years, which seems reasonable for a typical period between time of abandonment of a well, for example an oil or gas production well, and the use of that subsurface system for GCS. Furthermore, 50 years is the period required for post-injection site care (PISC) under Class VI, so there is a satisfying symmetry in this arbitrary number. With this choice, we see in Fig. 4 that the system leaks brine for 50 yrs at decreasing rates with time. Furthermore, the leakage rate is independent of where the leaky well is because the overpressure is uniform in the storage reservoir. Upon start-up of injection, the leakage is enhanced by the increased pressure arising from 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 the leaky wells located farther from the injection well, e.g. greater than 10 km, the leakage rate is only slightly enhanced following injection because the pressure of injection falls off with distance. The leakage rate is enhanced by 50–60% at 2 km from the injection well, and only by about 10% at 10 km from the well. These curves illustrate the fundamental results that (i) leakage occurs prior to injection, and (ii) leakage is enhanced by pressure of injection and these increases are highest near the injection well. This incrementally larger pressure drives brine leakage up the hypothetical leaky well. The overall decline in the background leakage rate from t = 0 to t = 100 yrs reflects the decline in hydraulic head gradient along the leaky well (i.e., the difference between the leakage-induced reduced pressure in the injection reservoir and the leakage-induced increased pressure in the USDW aquifer) caused by leakage up the leaky well. We emphasize that because of the pre-injection relative overpressure assumed in this scenario, 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.

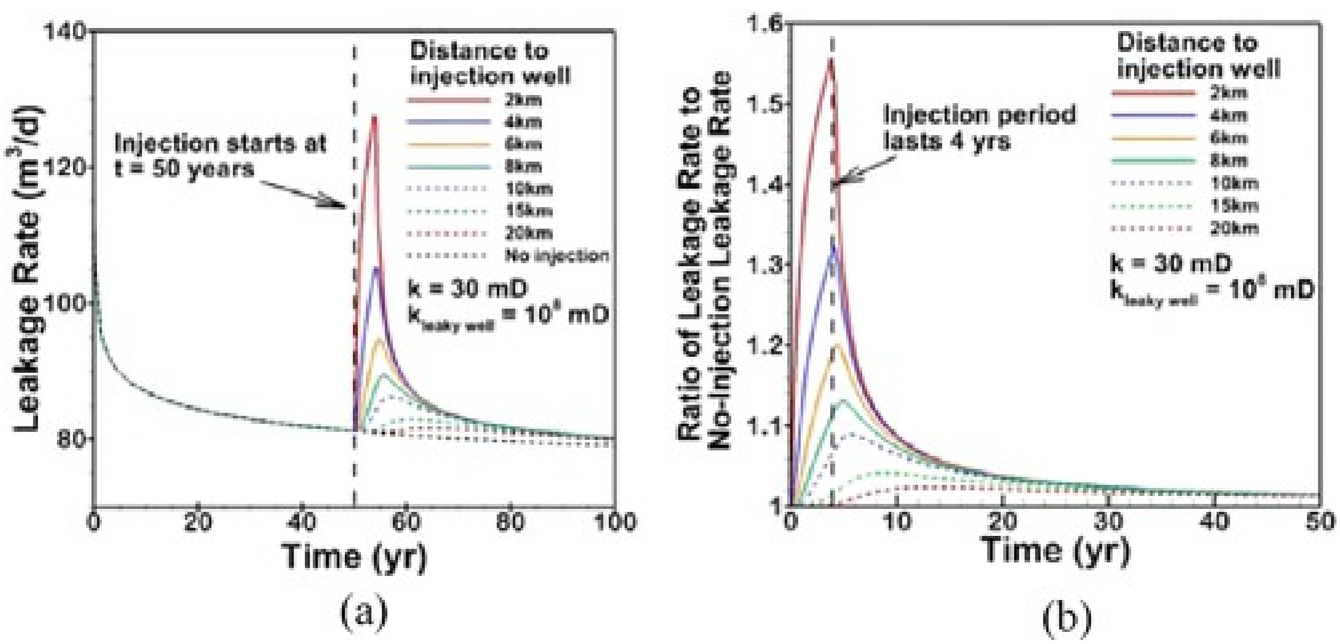

Figure 4

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(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 t = 50 years and lasts for four years. (b) Ratio of injection-related leakage rate to no-injection leakage rate.
Caption

In the case of pre-injection relative overpressure, one approach to estimating AoR under the Class VI regulation would be to evaluate the ratio or fractional increment in leakage rate that occurs due to the injection project and to impose a cutoff in this ratio below which no injection-related harm to USDW would occur. Figure 4(b) shows that the ratio of leakage rates is one way of quantifying incremental leakage.

For consistency with the basis of Class VI regulations, which is to protect USDW, it is not leakage rate but rather total cumulative leakage that should be used to evaluate AoR. To calculate such an incremental increase in the case of pre-injection relative overpressure, we need to assume one or more background, or no-injection, scenarios against which we can compare the injection scenario in terms of the ratio of cumulative leakage under injection normalized by cumulative leakage in the no-injection scenario cases. Among many choices for normalization, we evaluate here six methods (see Table 2) classified based on whether normalization is by instantaneous cumulative leakage or total cumulative leakage over some defined time period as follows:

Table 2. Classification of the six normalization methods.

			Normalization Methods					
			1	**2**	**3**	**4**	**5**	**6**
Numerator (amount of leakage)	Instantaneous cumulative (start of injection to time of interest)		X	X	X	X		
	Total cumulative (start of injection to 50 yrs)						X	X
Denominator (amount of leakage in no-	Instantaneous cumulative	−50 yrs to time of interest	X					

			Normalization Methods					
			1	2	3	4	5	6
injection case)								
		0 to time of interest		X				
	Total cumulative	−50 to +50 yrs			X		X	
		0 to 50 yrs				X		X

Normalization by instantaneous cumulative leakage

Normalization Method 1: Divide the CO_2-injection cumulative leakage (m^3) at each time for each well by the cumulative no-injection leakage that occurs starting at *t* = -50 yrs (50 yrs before injection started) until the time of interest. The period 50 years is chosen rather arbitrarily but with a nod toward post- and pre-injection temporal symmetry given the current Class VI 50-yr post injection monitoring period.

Normalization Method 2: Divide the CO_2-injection case cumulative leakage (m^3) at each time for each well by the cumulative no-injection leakage that has occurred starting at *t* = 0 yrs (start of injection) until the time of interest.

Normalization by total cumulative leakage

Normalization Method 3: Divide the CO_2-injection case cumulative leakage (m^3) at each time for each well by the total cumulative no-injection leakage over the period from *t* = -50 (50 yrs before injection started) until *t* = 50 yrs (46 yrs after injection stopped).

Normalization Method 4: Divide the CO_2-injection case cumulative leakage (m^3) at each time for each well by the total cumulative no-injection leakage over the period from t = 0 yrs (start of injection) until t = 50 yrs (46 yrs after injection stopped).

Normalization Method 5: Divide the CO_2-injection case total cumulative leakage (m^3) at each well by the total cumulative no-injection leakage over the period from t = -50 (50 yrs before injection started) until t = 50 yrs (46 yrs after injection stopped).

Normalization Method 6: Divide the CO_2-injection case total cumulative leakage (m^3) at each well by the total cumulative no-injection leakage over the period from t = 0 yrs (start of injection) to t = 50 yrs (46 yrs after injection stopped).

We show in Fig. 5 the results of cumulative incremental leakage using Methods 1 and 2. As shown in Fig. 5(a), Method 1 results in overall incremental increases on the order of 1–5%. We note further that the maximum, if any, in incrementally larger fluid leakage occurs after the injection has stopped for all distances plotted. The absence of maxima in the curves for large distances occurs because the baseline cumulative leakage volume is large but diminishing over the decades due to pressure dissipation caused by the leakage itself, 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, Method 1 produces apparently small incremental leakage flow because the normalization involves large background leakage.

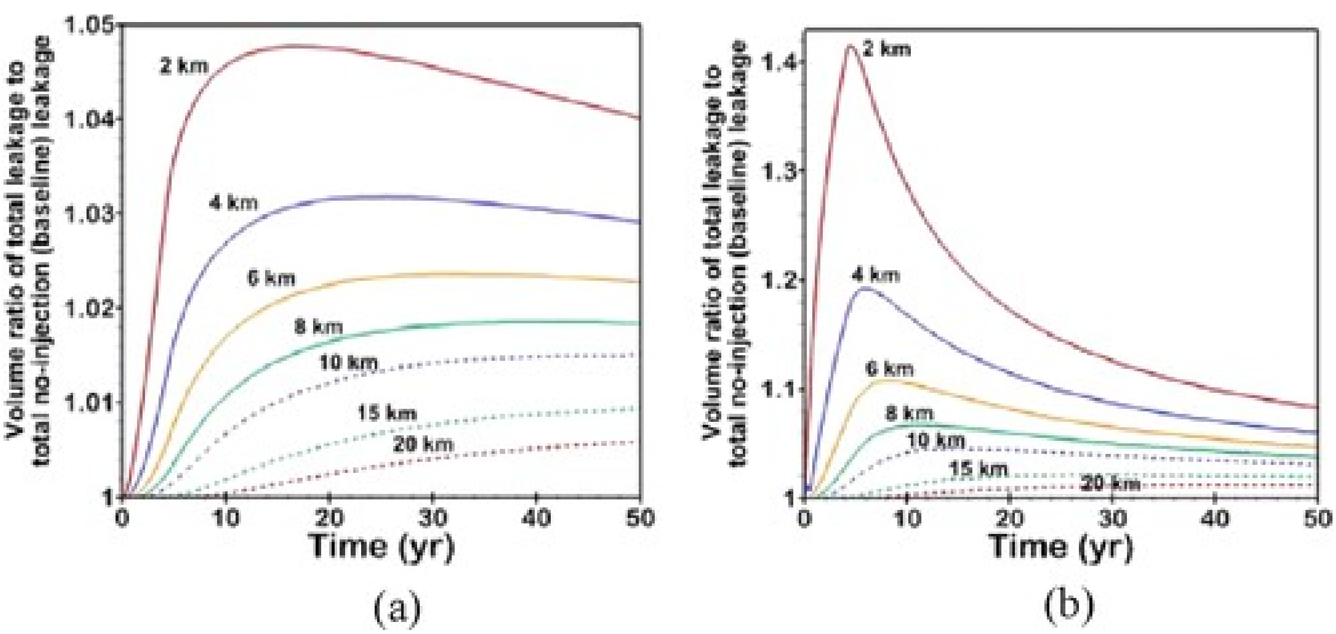

Figure 5

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(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.

Caption

Figure 5(b) shows the same results as shown in Fig. 5(a) only we use 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 in the denominator that was included in Method 1, and therefore this approach results in larger apparent incremental leakage (10–40% versus 1–5%). We emphasize that the absolute leakage amount is the same regardless of which normalization method is used.

We present in Fig. 6 the results for Methods 3 and 4 which normalize instantaneous leakage by the total cumulative leakage over the period t = -50 yrs to t = 50 yrs, and t = 0 yrs to t = 50 yrs, respectively. In these methods, the denominator is a constant so the cumulative leakages are monotonically increasing with time. We note that Methods 1 and 2 produced curves with maxima because during the post-injection period the growing cumulative leakage in the denominator over time makes the normalized cumulative leakage peak and decline eventually. In contrast, Methods 3 and 4 have constant denominators and serve to quantify the magnitude of the instantaneous cumulative leakage relative to total cumulative no-injection leakage over an arbitrary time period which can include a pre-injection period (Method 3). The lack of sensitivity of Methods 3 and 4 to distance from the injection well suggest these normalizations are not appropriate for clearly delineating AoR.

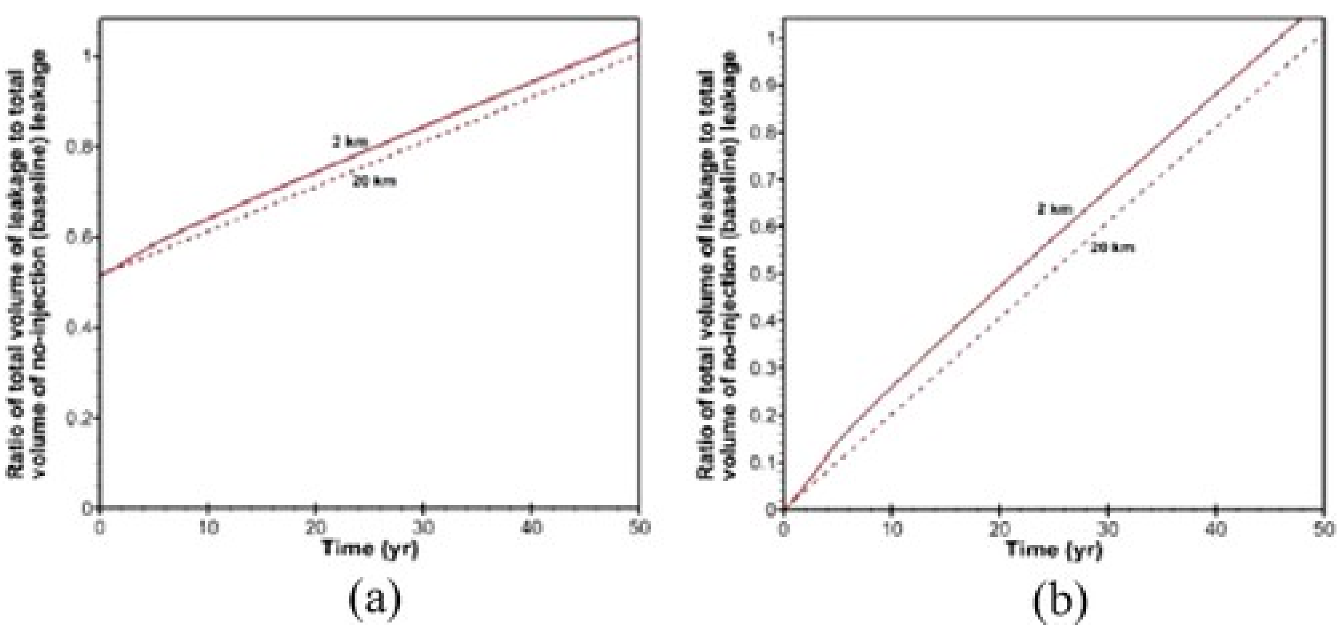

Figure 6

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(a) Total volume of leakage up to time of interest divided by total volume of no-injection-case leakage including 50 yrs of pre-injection leakage (Normalization Method 3) 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 4) for four years of injection starting at t = 0 yrs.

Caption

As for Methods 5 and 6, which normalize total cumulative leakage at each well by total cumulative no-injection leakage, the normalized leakage is constant with time but varies depending on distance from the injection well as shown in Fig. 7. Specifically, in the case considered here, the results of Methods 5 and 6 vary from 1.04 to approximately 1.08, respectively, for the well at 2 km distance from the injection well. These numbers provide a simple measure of how much the injection of CO_2 at the site increases the leakage into USDW depending on the distance of the various wells from the injection well.

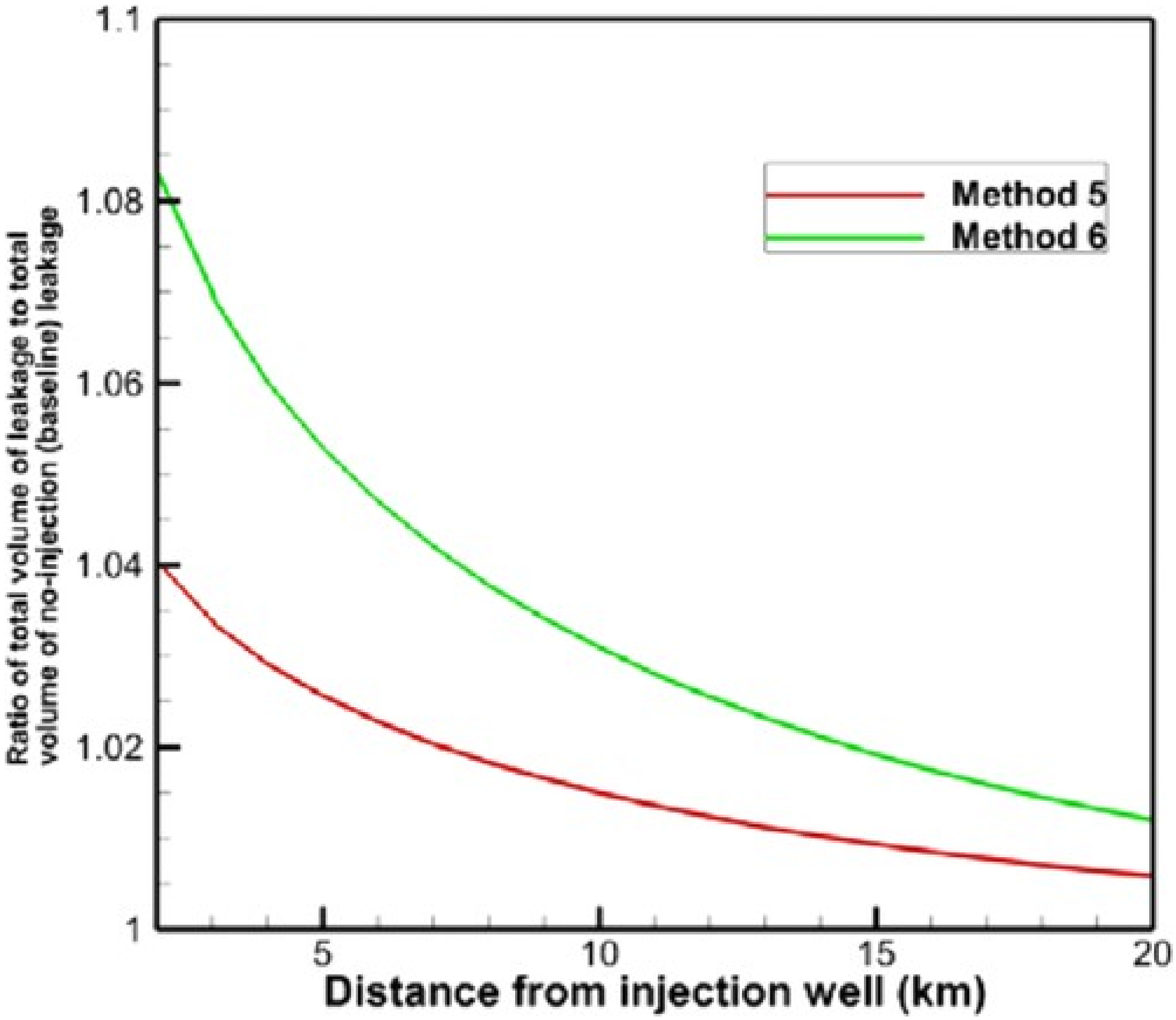

Figure 7

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Ratio of total injection-case leakage volume to the total no-injection-case leakage volume in Normalization Methods 5 and 6 as a function of leaky well distance from the injection well.

Caption

Discussion

The analysis and modeling presented here show clearly the importance of normalization method in evaluating the incremental (how much more) brine leakage that occurs for the case of an injection project relative to the natural (no-injection-project) base case. We are not in a position to recommend any one value for acceptable incremental increase, and we emphasize that the actual acceptable ratio of injection-related to no-injection leakage is an outstanding question that should be individualized for each site based on its unique circumstances. Furthermore, if the determination of acceptability is based on total brine leakage rather than leakage rate, the choice of how to compare injection-related total leakage to the no-injection case (base case) requires assumptions about pre-injection leakage, for example how long natural leakage was occurring and how much leakage occurred over that time. The need to assume pre-injection duration and rate of leakage exposes the incongruity between the assumption of a hypothetical open flow path and the presence of pre-injection relative overpressure. We arbitrarily 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 choice of 50 years was made arbitrarily here; this time period may be chosen differently in actual AoR estimations on a case-by-case basis, depending on the time of the leaky well starts to be operational in the field.

We point out that the reason that a choice arises for the length of the pre-injection time period is that the two features, pre-injection relative overpressure and an open flow path, are incongruous. Simply put, if an open flow path actually existed for millennial time periods in the system, there would likely be no pre-injection relative overpressure. Yet the presence of on open flow path demands that there be some pre-injection flow up the open flow conduit, leaving us to make an arbitrary assumption about the duration of this flow prior to, or even after (see next paragraph), injection. In order to be physically consistent, we believe that pre- (or post-) injection leakage should be included somehow in the comparison of natural background brine leakage to injection-related leakage.

For Normalization Method 1, we chose 50 years pre-injection as a time over which the background leakage would be considered because it was consistent with the 50-year post-injection monitoring period specified in the Class VI regulation. But it could be argued that the post-injection period is relevant also, and integration of total flow should be carried out for as long as the conduit remains open both with and without injection. For a leaking well, this period could include the age of the well pre-injection, until such time as the well is remediated and/or stops leaking, which could be potentially hundreds of years post-injection. Our Methods 3–5 assumes total time for pre-injection, injection, and post-injection is 100 years, while Method 4–6 assumes that only the injection plus post-injection period totaling 50 years are relevant. Methods 5 and 6 produce a time-independent ratio of incremental leakage that represents the net injection-induced impact. For a natural feature, it could be argued that integration should be carried out over a geologic time scale. We do not advocate any particular method, but rather we point out the wide variety of approaches simply to make the point that there are many ways to quantify incremental leakage, and we encourage the community to propose and defend the most plausible methods to continue the discussion leading to adoption by regulators of the most rational protocols.

Furthermore, we do not specify the cut-off of the ratio in each method for the definition of AoR because the ratio value depends on the geometric and hydrogeological properties of the storage systems, the initial value of relative overpressure, and the geometric and permeability properties of the leaky well. Here we have demonstrated various ways of calculating the ratio and its dependence (or independence) on time and distance between the injection and leaky wells.

Conclusions

We have analyzed and calculated brine leakage up hypothetical leaky wells located at various distances from a CO_2 injection well. We find that the incrementally larger flow rates and total leakage for hypothetical leaky wells located 10 km and 2 km from the injection well can be defensibly evaluated in at least six different ways. We emphasize that the actual brine 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. The need to choose an arbitrary time period for pre-injection leakage points out the inconsistency in the Class VI assumptions in which one needs to assume an open flow path even though pre-injection relative overpressure is known to exist. 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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