QUANTITATIVE ESTIMATION OF CO_2 LEAKAGE FROM GEOLOGICAL STORAGE: ANALYTICAL MODELS, NUMERICAL MODELS, AND DATA NEEDS

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ABSTRACT

Geological storage of CO_2 in mature sedimentary basins of North America requires special consideration of the large number of existing wells. Those wells represent potential leakage pathways for the stored CO_2, and must be analyzed in the context of an overall environmental risk assessment. Analysis of well patterns in the Alberta basin, Canada, indicates that injected CO_2 plumes are expected to contact from several tens to several hundreds of existing wells, depending on the local density of wells in the vicinity of the injection. Quantitative analysis of the impact of these wells requires an extensive data collection effort, analysis of materials used in well construction and abandonment, and different levels of computational modeling to ascertain the risk associated with these wells. New analytical solutions provide a promising avenue for leakage analysis at the large scale. Results from these models show accuracy comparable to more complex numerical simulators at a small fraction of the computational time. This allows many simulations to be run so that different parameters values can be explored. These large-scale models need to be coupled to smaller-scale detailed models of material behavior within the leaky well to provide a complete analysis of the problem.

INTRODUCTION

Geological storage of CO_2 is emerging as one of the most promising options for carbon mitigation. While this approach appears to be technically feasible, a comprehensive risk assessment is required to determine the overall effectiveness and possible environmental consequences of this approach. One important part of such a risk assessment is an analysis of potential leakage of injected CO_2 from the formation into which is injected, to other permeable formations or to the atmosphere. Such leakage is a concern because it may contaminate existing energy, mineral, and/or groundwater resources, it may pose a hazard at the ground surface, and it will contribute to increased concentrations of CO_2 in the atmosphere.

Pathways for possible leakage include diffuse leakage across caprock formations, concentrated leakage through natural faults and fractures, and leakage through human-made features such as wells. In areas where little oil and gas exploration has occurred, there are relatively few existing wells, and potential for leakage through existing wells is not a major concern. However, in mature sedimentary basins, like those in North America, more than a century of extensive oil and gas exploration has resulted in a very large number of existing wells. For example, in the State of Texas in the United States, more than a million wells have been drilled [1] while in the Province of Alberta in Canada, more than 350,000 wells have been drilled, with more than 15,000 new wells being drilled annually [2] and similar annual numbers of new wells forecast for at least the next decade. A significant fraction of the existing wells are abandoned [3], meaning that these wells are not monitored and have information associated with them that is of variable quality, depending largely on the age of the well. Because regions like these have very large numbers of existing wells, the potential for leakage through existing wells is an important concern that requires quantitative investigation. For context, a schematic of a possible well-leakage scenario is shown in Figure 1, where an injected CO_2 plume moves laterally (migrates) under the influence of both pressure drive and buoyancy, and then some of the injected CO_2 moves vertically upward (leaks) upon encountering a preferential flow path that corresponds to an abandoned well. It is this kind of scenario that requires quantitative analysis.

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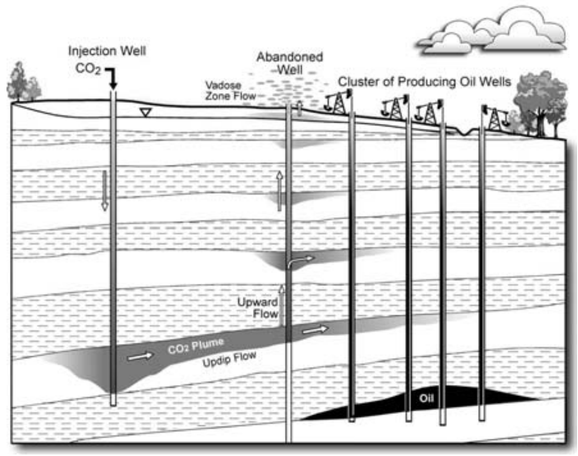

Figure 1: Schematic of injection, migration, and leakage along abandoned wells.

If an exploration well is drilled and the operator decides to abandon the well without further development, the open hole would typically be filled with a series of cement plugs, and the well would be abandoned. If the well is developed for production, then a casing would be inserted into the hole, and cement would be emplaced along a portion of the annular space between the casing and the rock. Possible leakage pathways along an existing well are shown schematically in Figure 2, and include possible preferential flow pathways along the rock-cement interface, along the casing-cement interface, and through degraded materials. Because well-formed cement has very low permeability, on the order of 10^{-20} m^2 (10^{-5} milliDarcy) [4], no significant flow of CO_2 can occur unless there are preferential flow paths, or the material has degraded, or the material was not formed properly during the emplacement process. If such preferential flow occurs, then the overall well materials need to be assigned a quantitative measure of flow potential, which involves parameters like the effective permeability of the composite materials associated with the well.

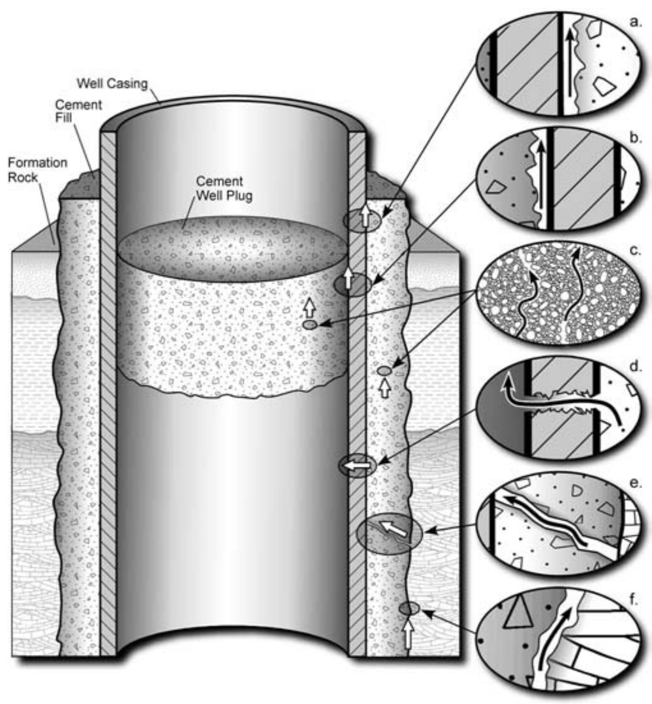

Figure 2: Potential leakage pathways along an existing well: between cement and casing (paths a and b), through the cement (c), through the casing (d), through fractures (e), and between cement and formation (f).

While intact well cements have very low permeability, and hence are good materials to use in well completions, the permeability of the overall well materials is very sensitive to relatively small changes in its configuration. A sensitivity study by [5], involving one injection well and one possibly leaky well, with permeability of the injection formation of 10^{-13} m^2 (100 milliDarcy), showed that at separation distances between the two wells of 500 meters, significant (greater than one percent) leakage occurred when the permeability in the leaky well was on the order of 10^{-10} m^2 (100 Darcy) or larger. This value, while being many orders of magnitude larger than the permeability of intact cement, corresponds to the effective permeability of an annular opening between the rock and cement that is approximately 1 millimeter thick. So, a thin (1 millimeter) degraded zone of cement, with very large permeability in the degraded zone, or an annulus associated with poor bonding of the cement to the rock, can lead to large effective permeability if the annular opening is continuous along the well. These extreme sensitivities of permeability values to small-scale irregularities in the materials, coupled with the large number of wells that exist in mature sedimentary basins, means that an in-depth analysis of this problem must be undertaken. Detailed studies of cement behavior on very small length scales, to properly capture possible small-scale system irregularities that can lead to significant leakage rates, must be coupled to analyses of injection and leakage at the field scale. The very large range of length scales over which the leakage analysis must be performed, from millimeters to tens of kilometers, is one of the features that makes this a challenging and scientifically interesting problem.

In this paper, we focus on development of large-scale modeling tools to quantify potential CO_2 leakage along existing wells. We begin with an overview of the problem, including specific analyses we have done to quantify spatial statistics of well locations in a mature basin. We then focus on modeling options and their relationship to uncertainty analysis. We focus particularly on new analytical solutions for injection and leakage. This work complements other ongoing work within our extended groups that includes upscaling studies to incorporate leaky wells into larger-scale numerical grid blocks [6], experimental and modeling work related to degradation of well cements [7] and analysis of plume evolution and extent in ongoing acid-gas injection operations [8].

SPATIAL ANALYSIS OF WELLS

We conducted a study of well locations in a formation in the Alberta basin in order to determine spatial characteristics of oil and gas well locations in a mature basin. The analysis was performed on all wells that penetrate the Viking Formation, which is an areally extensive formation that contains numerous oil and gas pools and has significant areas suitable for CO_2 storage (see [9]). The well locations show obvious clustering, which is expected given the nature of oil and gas pools in the formation and in the overall basin. In the higher-density areas, typically associated with oil production, the mean well density is close to 4 wells per square kilometer. Wells in these high-density regions account for about 30% of all wells that penetrate the Viking Formation. Medium-density wells account for another 30% of the wells, and have a density of about 1 well per square kilometer. These correspond roughly to gas producing clusters. The low-density background wells cover close to 90% of the area, account for a bit more than one third of the wells, and have a density of 0.15 wells per square kilometer. The low-density background regions also have the highest fraction of abandoned wells [9].

These numbers can be translated into number of wells that would be impacted by a typical injection scenario. If we estimate a typical CO_2 plume to evolve radially on the order of 5 kilometers, based on solutions in [10], [11], or [12], then we can analyze the spatial data to determine the number of wells impacted by an injection. Results of such an analysis, taken from [9], show that in high-density areas, the number of wells impacted by a plume is several hundred; the mean is 240, and the largest value is greater than 700. For injection into the low-density background regions, the numbers are much more modest, with a mean of about 18 and a maximum number of 130. See Table 1 for a summary of these statistics. These numbers indicate that, in the Viking Formation, injection operations should be expected to contact a significant number of existing wells, up to many hundreds per operation. Because the Alberta basin is characteristic of North America's onshore sedimentary basins, we expect these statistics to apply to other mature sedimentary basins. Note that these large numbers of wells distinguish the sedimentary basins of North America from most other regions of the world. For example, injection in deep formations that underlie the North Sea, where fewer than 20,000 wells have been drilled since the initiation of drilling in the 1960's, would involve only a relatively small number of wells that could potentially be contacted by an injected CO_2 plume. This implies that risk analyses for different regions of the world will need to focus on different critical pathways, depending on the history of development and the nature of the injection environment.

TABLE 1: SUMMARY OF STATISTICS (MEAN, MEDIAN AND RANGE) FOR THE NUMBER OF WELLS IMPACTED BY A TYPICAL CO_2 INJECTION (FROM [13]).

	Mean	Median	Range
High-density clusters	241.5	216	45-721
Medium-density clusters	62.6	61	8-144
Low-density Background	17.8	11	0-130

Analysis of the depth of wells in the Alberta basin indicates that maximum depth of drilling has increased consistently throughout the last century. Figure 3 shows summary statistics for all wells drilled in the Alberta basin, showing number of wells drilled, maximum depth of drilling, and average depth of wells. The mean depth is currently around 1000 meters, and the maximum depth now stands at about 7 kilometers. While well densities decrease with depth, and are restricted by areal variations in geological depth, even deep formations will have had some drilling activities over the last few decades.

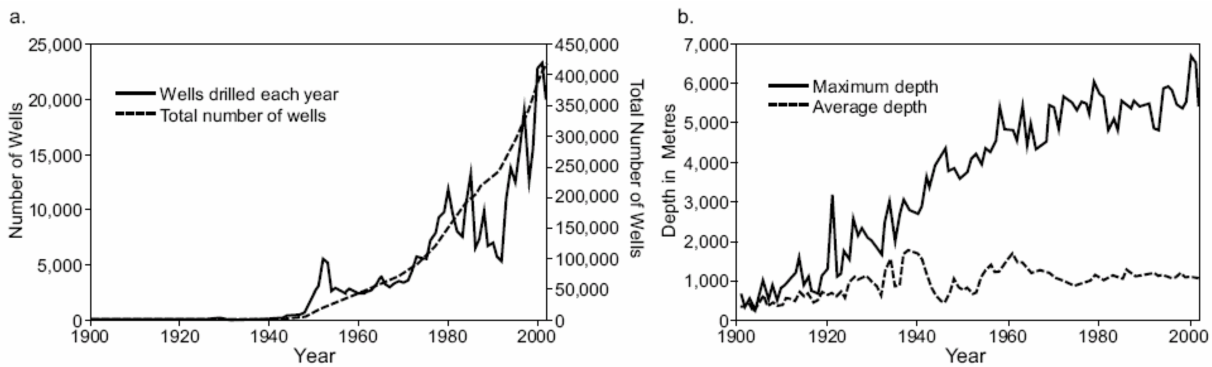

Figure 3: (a) Number of wells drilled in the Alberta basin as a function of time, and (b) Average depth and maximum depth of penetration of wells drilled in the Alberta basin, as a function of time.

MODELING APPROACHES INCLUDING MULTIPLE EXISTING WELLS

Injection of CO_2 into locations in mature sedimentary basins of North America might reasonably be expected to produce a CO_2 plume that contacts tens to hundreds of existing wells. Because of the extreme range of length scales that are important to this problem, a wide range of models is required, ranging from small-scale models of geochemical degradation of well cements, to large-scale models that include tens to hundreds of existing wells over hundreds of square kilometers. The high degree of uncertainty associated with individual wells, including variability in original emplacement of well cements, types of materials used, and material degradation over time, means that a risk analysis will require many simulations that encompass the range of possible parameters associated with individual wells. In addition, for locations whose data reporting is not as comprehensive as in the Province of Alberta, locations of abandoned wells can also be quite uncertain. This uncertainty associated with existing wells adds to the usual uncertainties associated with material properties of the geological formations, which for multi-fluid flow problems include intrinsic permeability and porosity, as well as nonlinear functional relationships for relative permeability and capillary pressure. In addition, equations of state are complex, and geochemical degradation is strongly dependent on fluid compositions, both the original background composition of resident fluid(s) and the modified compositions associated with introduction of CO_2 into the system. All of these data and parameter uncertainties create a problem that has a complex multi-dimensional parameter space with potentially wide ranges of possible values along the parameter axes. Because of the scale disparity and the large degree of uncertainty, and the resultant large number of simulations that will be needed to perform a risk analysis, computational efficiency of models becomes a concern, and different modeling options need to be considered.

The problem is made even more complex by the need for parametric information for all formations between the injection formation and the land surface. This is needed because wells are continuous features, extending from the land surface to the deep subsurface formation of interest, and leakage through a well can result in leaked fluid contacting all formations along the well as it proceeds toward the land surface and eventually reaches the atmosphere. An example of the possible importance of intervening geological layers is provided by [13], who analyzed the case of waste injection involving single-fluid flow. For the layered system illustrated in Figure 4a, the leakage that reaches the surface is reduced by many orders of magnitude due to the availability of permeable layers along the vertical column. These layers serve to attenuate the leakage as it proceeds along the leaky borehole, as shown in Figure 4b. While the CO_2 leakage problem is more complicated because of the two-fluid flows involved, this simple result still indicates that site characterization for potential injection locations should include an analysis of the entire vertical sequence, not just the target injection formation and its immediately adjacent caprock layer.

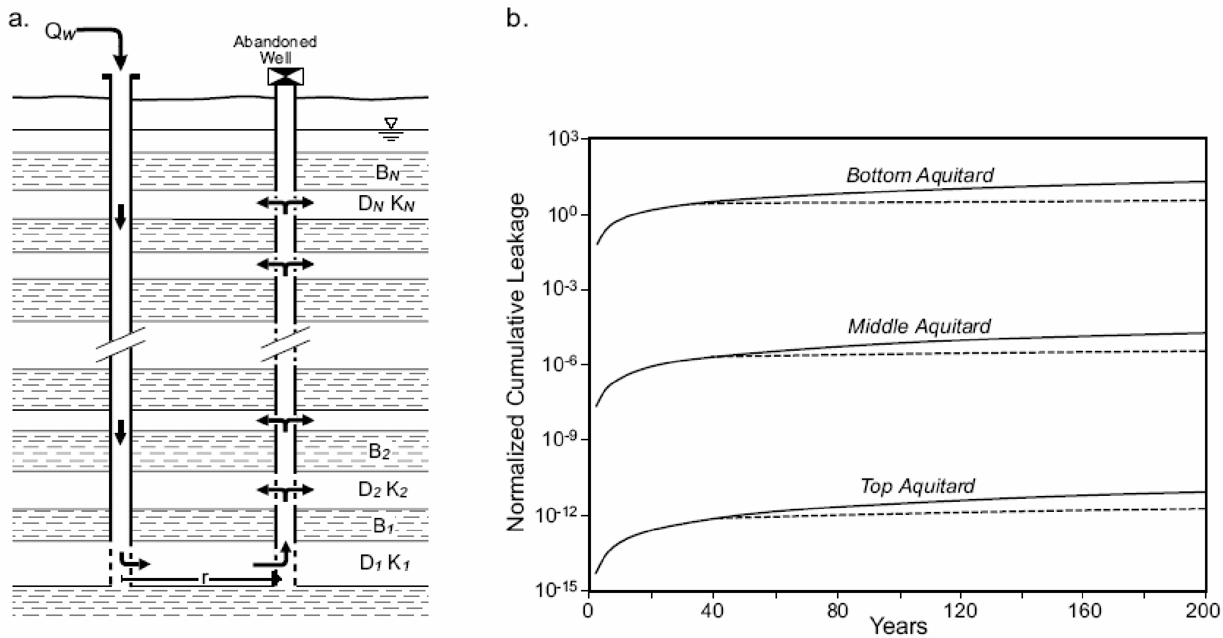

Figure 4: (a) Schematic showing injection well and leaky well in a multi-layer system, and (b) Cumulative leakage rates, normalized by amount injected, for leakage through the lowest aquitard, the middle aquitard, and the upper-most aquitard, in a domain with 11 aquifers and 10 aquitards, with solid line representing continuous injection and dashed line representing injection for the first 30 years (taken from [17]).

A usual approach for modeling multi-fluid flows in porous media, of the kind that are expected to occur with CO_2 injection, is to use a standard numerical model like ECLIPSE [14] or TOUGH2 [15]. These models use traditional finite volume types of approximations, with different options for equations of state and other parameters. In these kinds of models, wells are defined as features that have some external control of fluid flow, with either flow rates or bottom-hole pressures prescribed as known information. We will refer to these types of wells as active wells. A leaky well is different, in that there is no external control exerted on the well. As such, a leaky well simply acts like a streak with different material properties within the formations, with the important characteristic that it is spatially continuous from the land surface to the formation in which it is completed. Of course, the well materials, and therefore the associated material properties, may vary along the length of the well. However, the leaky well constitutes a problem of extreme heterogeneity, where the heterogeneous feature is pencil-like in its shape. We will refer to wells for which no external forcing is applied as passive wells. Passive wells include abandoned wells and any other wells that are not in operation (e.g., suspended).

Numerical simulators often require fine grid spacing in the vicinity of wells. For problems with tens to hundreds of wells, this implies fine gridding almost everywhere in the domain, which can lead to enormous computational requirements. Advanced numerical techniques such as local grid refinement and local time stepping [16] could alleviate this burden to some extent. Upscaling methods (see [6], [17], [18], and references therein) may also be used to incorporate the heterogeneity associated with a passive well into a larger grid block. In grid cells containing a passive well, upscaled, or averaged, intrinsic permeability leads to an anisotropic effective permeability. More interesting is the relative permeability function, which is also anisotropic, and for which a simple pseudo-function approach can yield leakage estimates up to eight times too large [6]. This is due to cross-flows between the background rock and the well, which causes complex three-dimensional flow patterns locally. Possible solutions include improved upscaling formulations, and use of a dual-medium description in grid cells that contain wells [6].

While numerical solutions have the advantage of allowing flexible geometries and quite general material properties, the large number of wells that are involved in these kinds of leakage problems leads to consideration of analytical solutions as a simplified approach that retains sufficient physics to make the results useful. A wide range of analytical solutions exists for problems involving a single fluid and a single well. These form the basis of well testing. Solutions that include multiple wells, where some of the wells are passive, are more difficult to solve. Recently, Nordbotten et al. [13] solved the single-fluid problem involving multiple wells and multiple layers. That solution is the basis for the results shown in Figure 4. The extension of the solution to the case of two fluids, corresponding to injection of CO_2 into a deep saline aquifer, requires use of more complex mathematical techniques. One of our approaches to this problem is based on the idea that, for a given injection operation, the fluids in the system will arrange themselves at any time to minimize the amount of energy required to inject the given mass of fluid. If we include in the definition of energy (or work) the energy associated with the viscous flow, as well as the buoyant forces associated with the density differences between the two fluids, then it turns out that the solution is governed by the following dimensionless parameter Γ, defined by

$$\Gamma = \frac{2\pi\Delta\rho g \lambda_w k B^2}{Q} \tag{1}$$

In Equation (1), $\Delta\rho$ is the density difference between the two fluids, assumed to be formation brine and CO_2, Q is the injection rate for CO_2 (assumed constant), λ_w is the mobility of the water (brine), defined as the ratio of relative permeability to viscosity [$M^{-1}LT$], k is the intrinsic permeability of the formation [L^2], and B is the thickness of the formation [L]. The dimensionless group Γ identifies when the gravity (buoyancy) force is important relative to viscous and pressure forces. Our analysis [12, 19] indicates that when $\Gamma<0.5$, the viscous losses dominate the solution and the density difference only serves to segregate the CO_2 in the vertical. When $\Gamma>10$, buoyancy is dominant in the solution for the CO_2 plume and must be included in the solution. Intermediate values of Γ indicate the transition region. Our calculations for generic conditions in sedimentary basins and for actual cases of acid-gas injection in the Alberta basin indicate that, under most conditions expected for practical CO_2 injections, Γ is small and therefore buoyancy forces are small relative to the viscous forces [8, 12]. This allows for significant simplification, and the resulting CO_2 profile is captured well by the following solution

$$\frac{b(r,t)}{B} = \frac{1}{\lambda_c - \lambda_w}\left[\sqrt{\frac{\lambda_c \lambda_w V(t)}{\varphi \pi B r^2}} - \lambda_w\right] \tag{2}$$

In Equation (2), $b(r,t)$ is the thickness [L] of the CO_2 plume at radial distance r and time t (see Figure 5), $V(t)$ is the cumulative volume of injected fluid [L^3], φ denotes porosity [L^0], and λ_c is the mobility of CO_2 [$M^{-1}LT$].

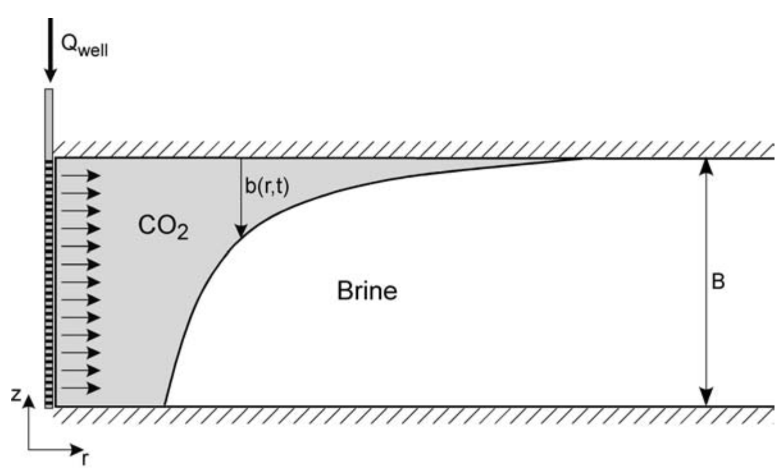

Figure 5: Typical profile of CO_2 plume defined by thickness $b(r,t)$.

Equation (2) applies for all values $0 \le b \le B$. When $b<0$ in Equation (2) the solution is set to $b=0$, and when $b>B$ the solution is set to $b=B$. Of course, when $\lambda_c = \lambda_w$, Equation (2) does not apply and the solution is a simple cylindrical region of volume V(t). For cases of small Γ, such that Equation (2) applies, gravity acts to vertically segregate the injected fluid and to smooth viscous fingers that are generated because of unfavorable viscosity ratios, but the dominant mechanism for energy loss is viscous dissipation. For cases of larger values of Γ, which correspond to very permeable and thick aquifers or slow injection rates, it appears that Equation (2) can be replaced by a similarity solution, which, while being somewhat more complicated, still fits into our overall framework as described herein. We note that Equation (2) corresponds to a solution of the redial Buckley-Leverett equation in which linear relative permeabilities are used, and for which capillary pressure is neglected (see, for example, [20] and [12]).

These analytical solutions, which describe the CO_2 plume evolution due to active injection, can serve as building blocks for analysis of leakage through passive wells in the vicinity of an injection well. Combination of the two-fluid injection solutions with concepts presented in [12], and with additional considerations due to the nonlinear nature of the CO_2 injection problem, allows us to derive semi-analytical solutions for the passive-well leakage problem. An example of a calculation of leakage associated with CO_2 injection, modified from [19], is shown in Figure 6. In the problem, a passive leaky well is located almost one kilometer (953 m) away from an injection well. The injection formation is 30 meters thick and is overlain by a 100-meter thick aquiclude, above which is a permeable formation that is also 30 meters thick. The leaky well has permeability in these vertical regions only, and the entire system is impermeable above and below. Fixed pressure boundaries are specified in the horizontal, with the horizontal domain covering approximately 125 km^2. Both permeable formations have permeability $k=2 \cdot 10^{-14}$ m^2 (20 milliDarcy), and the leaky well is assigned a range of permeability values. The porosity is 15% in both formations and in the leaky well. The injection rate is 1600 m^3/d, and density and viscosity values are 1045 kg/m^3 and 0.2535 mPa·s for the brine and 479 kg/m^3 and 0.0395 mPa·s for the CO_2. These values give a value of $\Gamma = 0.02$ in the injection formation. Figure 6 shows dimensionless leakage rate of CO_2 through the leaky well as a function of time, for several different scenarios, where the leakage rate is expressed as a fraction of the CO_2 injection rate, normalized by the ratio of permeability in the leaky well to the permeability in the injection formation. Included in the figure are the following solutions: semi-analytical solutions for three different permeability values assigned to the leaky well, and associated solutions from the numerical simulator ECLIPSE. From these results we observe the following: (1) The semi-analytical solution for this problem matches well the numerical simulations from Eclipse for all cases; (2) Higher leaky-well permeability leads to larger leakage rates, as expected; (3) Higher leakage rates in the leaky well induce stronger local decreases in pressure around the leaky well, which serves to induce increased brine flow in the leaky well. This 'upconing' of the brine into the well leads to a much more gradual rise in the leakage rate for the CO_2, which corresponds to a much longer time period of two-fluid flow in the leaky well. The solutions include the parameter b_{max} (see Figure 6), which characterizes the upconing effect, as derived in [19]. It represents the thickness of the CO_2 plume, measured at the leaky well, that is required to achieve full saturation of CO_2 within the leaky well and thereby prevent further upconing of the brine.

The excellent match with the numerical simulations indicates that the semi-analytical solution provides reliable results that capture the essential features of the system quite well. These solutions offer a high level of efficiency: solutions shown in Figure 6 take only a few seconds to calculate, while the Eclipse runs typically take several hours. Therefore these kinds of simple analytical solutions can be embedded into calculations involving uncertainty analysis, where many simulations need to be performed in order to sample the possible parameter values. However, the analytical solutions are also restricted by the assumptions inherent in their derivation. These include the assumption that the permeable formations are horizontal, with constant thickness and constant material properties (although properties can vary from one layer to another), and that the dominant flow is horizontal. The injected CO_2 plume is assumed to be radial, even in the presence of CO_2 leakage through one or more leaky wells. The properties of the fluids are assumed to remain constant within each formation, although they can change from one formation to another. And the permeability of caprock formations is assumed to be zero. Dissolution of CO_2 into the brine can be included behind the invading CO_2 front, as can non-zero residual water saturations. Also, inclusion of compressibility and pressure-dependent viscosity changes for the problem associated with Figure 6 produces leakage results that differ very little compared to the results shown in the figure, indicating that an assumption of constant fluid properties is reasonable for this problem. Overall, depending on the problem complexity, and the amount of data available to resolve spatial variability, this group of assumptions may or may not be appropriate. Our opinion at this time is that for many problems these simplified analytical solutions represent a reasonable compromise between complex numerical models and the need for rapid solutions for large-scale analysis of risk and feasibility.

There is one key 'fitting' parameter in the model at this time, and that is the parameter b_{max} that defines the degree of upconing. We have independent analytical solutions specifically for the upconing problem that give insights into how to choose this parameter, but that work is not yet complete.

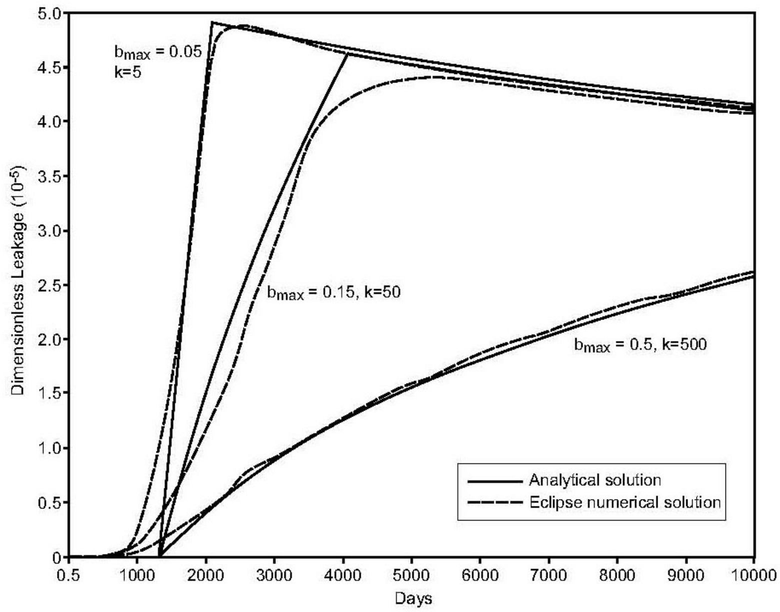

Figure 6: Leakage rate of CO_2 through an abandoned well, for three different permeability values assigned to the leaky well. Dimensionless leakage is leakage rate divided by injection rate, normalized by the ratio of formation permeability to leaky-well permeability. Best-fit values of the parameter b_{max} are shown for each curve. Leaky-well permeability values are shown for each curve in units of Darcy.

The question of upconing around the leaky well, and the associated simultaneous flow of brine and CO_2 through the well, has interesting implications for possible degradation of well materials. Degradation of well cements results from acidified brine that is flowing past, or through, the cement. Higher flow rates and higher acidity both imply faster degradation. For slow flow rates, not only is the degradation rate slower, but the time period during which both fluids flow in the well is also shorter. Once CO_2 saturates the well material, then acidified brine is no longer able to flow (although wet CO_2 and its corrosive effect on the well casing may be a concern for the following period of time). Conversely, when the flow rate is higher, then stronger upconing produces longer periods of acidified brine flow, so that degradation rates are not only faster but they persist longer. This behavior provides a positive nonlinear feedback between the degradation and flow processes. The active leakage of brine also highlights the dynamics of the brine in the context of well leakage.

CONCLUSIONS

In mature sedimentary basins in North America, extensive oil and gas exploration and production has resulted in a large number of existing wells, whose number continues to increase. Because drilling activity has been areally extensive, with significant regions of high areal density, existing wells must be included in any comprehensive risk analysis of CO_2 injection. A study of a specific formation in the Alberta basin showed that in areas of high well density, several hundred wells will be contacted by a typical CO_2 plume, while in the sparse background regions only about 20 wells will be contacted on average. Properties of these passive wells are difficult to assign and have a high degree of uncertainty.

New semi-analytical models for injection and leakage provide simple computational tools for quantitative estimation of leakage. While being more restrictive than general numerical models, they provide extreme efficiency while capturing the essential features of the flow processes. These simplified models should allow for comprehensive uncertainty analysis, where many simulations are required to explore the wide range possible values within the parameter spaces associated with this problem.

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