CONFERENCE PROCEEDINGS

Modeling Critical Leakage Pathways in a Risk Assessment Framework: Representation of Abandoned Wells

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Abstract

In many locations in North America, likely injection sites for CO_2 storage in deep geological formation are located in mature sedimentary basins. These basins have a century-long history of oil and gas exploration and production, which has led to hundreds of thousands of wells (the Alberta Basin) to more than a million wells (Texas) being drilled. The spatial density of these wells is on the order of 0.5 to 5 wells per square kilometer. Therefore, a typical injection will produce a CO_2 plume that intersects hundreds of existing wells, many of which are abandoned and some of which have uncertain or unknown locations. In order to analyze the leakage potential in such situations, computational models must be developed that can cover large spatial areas (of order 1,000 km^2) while resolving the local flow dynamics in all of the hundreds of wells. In addition, both the layered structure of the subsurface, and possible leakage along wells and into successive overlying permeable layers in the subsurface, also need to be represented. We have developed a semi-analytical model that can simulate all of these attributes, over decadal to century time scales, while running quickly on a laptop computer. With this tool, risk assessment based on Monte Carlo analysis can be carried out, and a quantitative analysis of leakage potential can be performed.

Introduction

The century-long history of oil and gas exploration and production in sedimentary basins in North America has resulted in millions of existing wells [1]. If CO_2 is injected into these mature sedimentary basins, the resulting CO_2 plume is likely to intersect tens to hundreds of existing wells [2]. In these systems, possible leakage pathways along the existing wells represent a critical leakage pathway for CO_2 storage systems [1, 3, 4]. Possible leakage pathways along a well are shown in Figure 1, while the overall idea of leakage along these wells is shown schematically in Figure 2. The problem is complicated by the possible effects of acidified brines, generated by interactions with CO_2, because such acidified fluids can cause degradation of well construction materials and thereby enhance possible leakage [4].

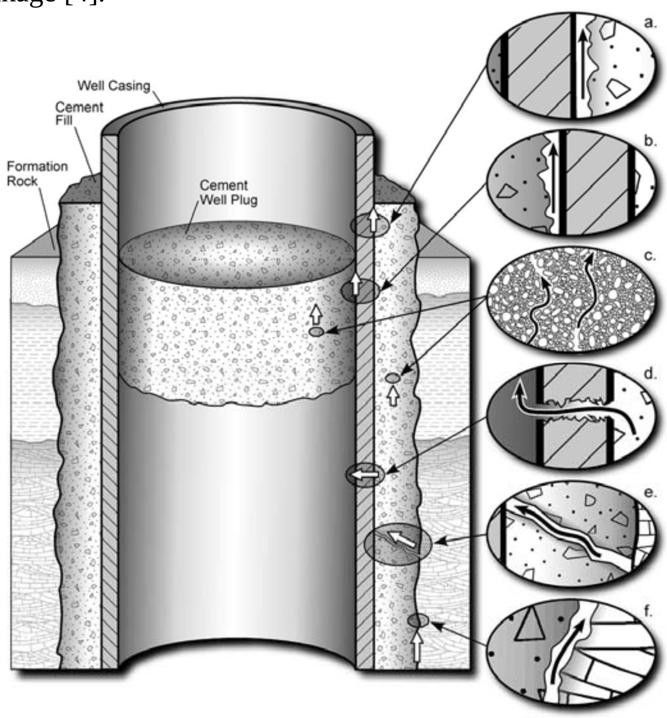


FIGURE 1: Schematics of possible leakage pathways along a well (from [2]): (a) between cement and outside of casing, (b) between cement and inside of casing, (c) through cement, (d) through casing, (e) in cement fractures, (f) between cement and rock.

The range of length scales associated with this problem is impressive. A typical CO_2 injection plume is likely to extend five to 10 kilometers in the radial direction [5]. The pressure field associated with injection will extend further. Therefore, the length scale for an overall injection scenario is on the order of hundreds to thousands of square kilometers. A typical well radius is on the order of 10 centimeters, and the annular thickness of well cement between casing and formation is on the order of a few centimeters. Within this well system, an annular opening of one millimeter, for example, between the cement and the formation rock, can allow for substantial flows along the well. Geochemical reactions along the well occur in regions that are on the order of perhaps hundreds of micrometers. So the resulting system has important length scales that range from fractions of a millimeter to tens of kilometers. This range of seven to eight orders of magnitude makes modeling these features challenging. A model meant to capture overall system response to injection, with possible leakage along very small, line-like features, must adequately address these highly disparate length scales.

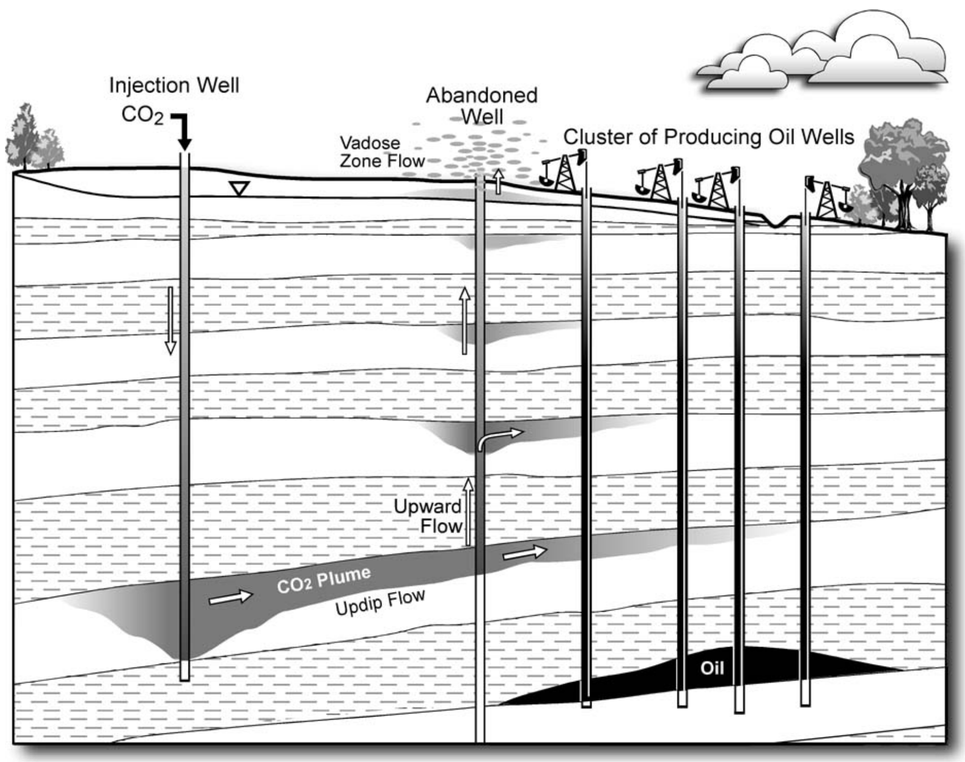


FIGURE 2: Schematic of CO_2 injection plume and possible leakage pathways along existing wells (from [2]).

Options to model this system include multi-phase numerical models, like Eclipse [6], TOUGH2 [7], STOMP [8], and many others. To resolve the necessary features of the system, in this case the line-like features of possible high permeability, adequate discretization is necessary around each well. Furthermore, as shown by Nordbotten et al. [9], the vertical structure of the system can strongly impact the flow along a leaking well. Therefore, models should also include an adequate vertical discretization. In systems with several hundred wells, and perhaps five to ten formation layers in the vertical succession, the number of grid cells is likely to be prohibitive. Therefore, we are motivated to seek simplified models that capture the dominant physics of the processes of interest, while ignoring others that are not dominant.

An attractive option for modeling CO_2 injection with possible leakage along a series of existing wells, in a vertically layered system, is to use analytical or semi-analytical solutions. A variety of analytical solutions have been developed over many decades to model fluid flow in porous media. Among the most important and useful analytical solutions are those of Theis [10], Buckley and Leverett [11], van Lookeren [12], and the general solution approaches described in Barenblatt [13], all of which deal with single formations and one- or two-phase flows. Solutions focused on leakage through abandoned wells include the work of Javandel [14], Avci [15], and Nordbotten et al. [9], which dealt with single-fluid flow, and the recent work of Nordbotten et al. [16] that deals with two-fluid flows and leakage.

In this manuscript, we outline a semi-analytical solution method and approach that we have developed to model the injection of CO_2 into deep subsurface formations, where many existing wells may occur within the radius of influence of the injection plume. The model is semi-analytical. Each component of the model will be described briefly, the major assumptions associated with the model will be listed explicitly, and an example calculation will be included to demonstrate the potential power of the approach.

A Semi-analytical Model for CO_2 Injection and Leakage

The model for injection and leakage dynamics has five major parts:

(1) Solutions for injection dynamics and CO_2 plume evolution;
(2) Solutions for leakage along wells;
(3) Solution for upconing around leaky wells;
(4) Determination of secondary plumes of CO_2 that invade intervening layers, fed by leakage along a well; and
(5) post-injection plume behavior.

Below are brief descriptions of each of these components.

Injection Dynamics and Plume Evolution

Analytical solutions have been derived for a variety of injection scenarios involving constant-rate injection of supercritical CO_2 into a deep, confined saline aquifer. The solutions are based on assumptions of a sharp interface between the injected CO_2 and the resident formation water, homogeneous and horizontal aquifer, and vertical equilibrium of pressure (see Nordbotten and Celia [17] for a discussion of this assumption). The general similarity solution is based on the idea that the system has inherent scaling based on the ratio of r^2/t, where r is radial distance from the injection well, and t is time. The solution can then be determined by solving a set of ordinary differential equations, with the solution being a function of only the similarity variable (r^2/t). In cases where viscous forces dominate, the result can be simplified to the radial Buckley-Leverett solution [18], which takes the following simplified equation form

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

where b is the thickness of the CO_2 layer (see Figure 3), B is the aquifer thickness, λ_c and λ_w are fluid mobilities for CO_2 (c) and brine (w), Q_{well} is the CO_2 volumetric injection rate, t is time, φ is porosity, and r is radial distance from the injection well. This provides a simple estimate for extent of CO_2 plume [19]. The result of [18] also provides equations for the pressure buildup in the injection formation.

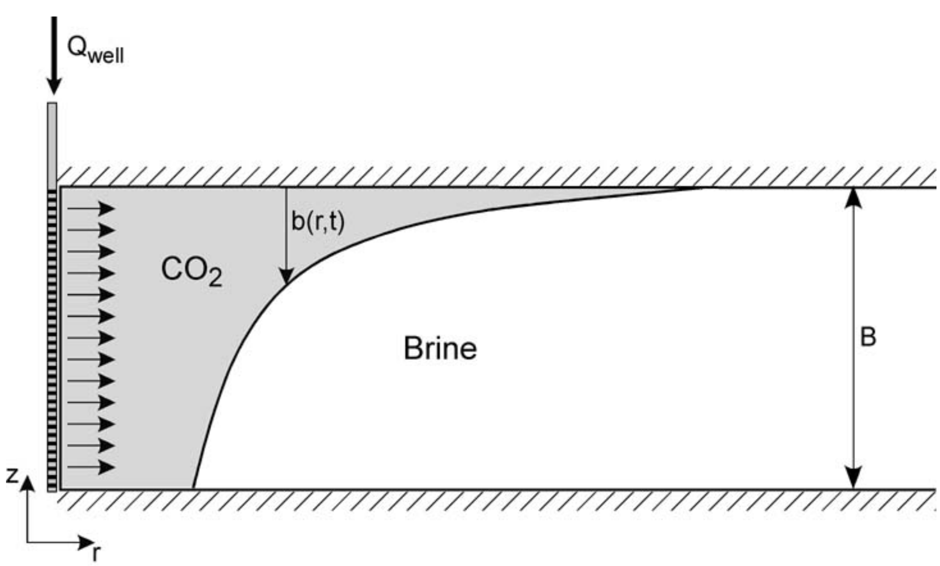


FIGURE 3: Schematic of shape of injected CO_2 plume, showing thickness of the CO_2 layer and the associated sharp interface (from [18]).

Well Leakage

The pressure increase in the injection formation can drive fluid leakage (both brine and CO_2) along defective wells within the radius of influence of the injection, if the materials in these wells have imperfections that allow for fluid flow (see Figure 1). If leakage of fluid(s) occurs, the flow rate will be determined by the pressure field and the fluid properties (density and viscosity). In turn, the pressure field around the leaky well is modified by the leakage, due to drawdowns around the leaky well. Because the flow rate along the leaky well is variable in time, the effect of the leakage leads to a convolution integral in the governing equations (see, for example, [9]). Nordbotten et al. [9] developed a very efficient approximation to these integrals, that allowed for solution to be computed for single-fluid injection and leakage in systems with arbitrary numbers of wells and layers in a system with alternating aquifer-aquiclude layers in the vertical direction. This solution was extended, and combined with the CO_2 injection solution of [18], to produce a solution for CO_2 injection and associated leakage of brine and CO_2. The underlying approach is presented in [16] for the case of a single injection well, a single leaky well, and a two-aquifer-one-aquiclude system. More recently, we have extended the CO_2 leakage solutions to include arbitrary numbers of wells and layers. We report on initial results of this extended model in the Results section below.

Upconing around Leaky Wells

When leakage occurs along a well, the flow induces a pressure drawdown in the vicinity of the well. This drawdown has potentially significant implications for the behavior of the CO_2 plume in the vicinity of the leaky well. In particular, the leakage-induced drawdown leads to an upconing of the more dense brine, which underlies the less-dense carbon dioxide. This upconing is analogous to the behavior of salt-water when a freshwater lens of groundwater is pumped in a coastal aquifer. The interface retreats upward, and this can result in the simultaneous flow of brine and CO_2 along the leaky well, at least for some time period. The significance of this two-phase flow is that acidified brine, caused by CO_2 dissolution into the brine, is the phase that can attack well cements. The presence of CO_2 along with the brine implies a continuous source for dissolved CO_2 in the brine, and therefore implies the possibility of aggressive cement attack by the flowing fluids. For this reason, a model of the interface upconing must be included in the overall model of injection and leakage. We have developed a model for this system, which estimates the conditions under which two-phase flow along the well occurs. This model eliminates the only fitting parameter that appeared in the solutions of [16], where the parameter was referred to as b_{max}, which represents the thickness of CO_2 plume required to completely block brine from flowing along the leaky well.

Models of Secondary Plumes

When an injection CO_2 plume encounters a leaky well, and CO_2 leaks upward along the well, a secondary plume may develop within one of the intervening permeable layers. An example of this behavior is shown in Figure 2. These secondary plumes lead to CO_2 being stored at intermediate depths in the subsurface, which serves to mitigate the amount of leakage that reaches the shallow subsurface or the atmosphere. These plumes are modeled in the same way as the primary plume, although the amount of CO_2 flowing into the formation is not know *a priori*, but instead is determined as part of the solution.

Post-injection Plume Redistribution

Once injection ceases, the dominant pressure drive in the system decays, and the plume is left to redistribute its mass under the influence of buoyancy while controlled by mobility and possible capillary trapping. At long times, the plume behavior can be modeled by equations in the literature, using the similarity methods of Barenblatt [13]. At the early times after injection ends, the algorithm we use is based on a smooth decay of the CO_2 interface location. The model can include residual CO_2 saturations behind the receding CO_2 front, analogous to the way that residual brine is included behind the front during injection. During this phase of the problem, all leakage and secondary plume calculations continue, and leakage calculations continue as they did during injection.

Summary of Major Assumptions

The major assumptions that are used in the current model are:

1. *Horizontal layers* – All layers in the system are assumed to be horizontal.
2. *Homogeneous layers* – All layers in the model are assumed to be homogeneous, although material properties can vary from one layer to the next.
3. *Impervious caprock layers* – All caprock layers are assumed to be impervious, so leakage takes place only through wells.
4. *Vertical Wells* – All wells in the system are assumed to be vertical.
5. *Radial plumes* – All plumes, both primary and secondary, are assumed to maintain radial symmetry. The algorithm redistributes mass at each time step to assume radial symmetry while conserving mass.
6. *Neglect of capillary pressure* – Capillary pressure is neglected in the solutions. See Nordbotten et al. [18] for a discussion of this.
7. *Neglect of thermal effects* – No energy balance is performed, so temperature profiles must be given as known information. As such, instant thermal equilibration between the fluids and the medium is assumed.

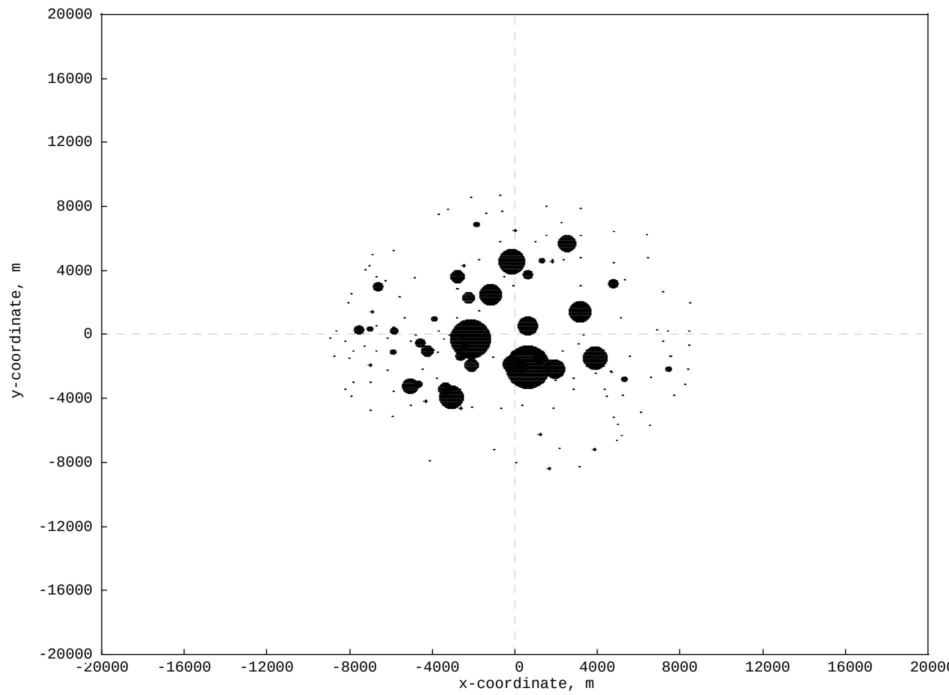
Numerical Example

To demonstrate some of the capabilities of this new model for leakage, we have developed a data set based on an area close to Edmonton, Alberta, Canada, where there are several large point sources of CO_2 emissions (coal-fired power plants). Within a domain that is 30 km by 30 km (3 by 3 townships), 503 existing wells were identified, and the layered geology of the region was also determined based. This led to a model with 13 layers in the vertical (7 permeable and 6 impermeable), covering the 900 km^2 region. The existing wells were each characterized by an effective permeability. Each well was assigned a permeability from a random distribution that was taken to be bi-modal, with one mode having a mean of about 10^{-20} m^2, while the second mode was assigned a higher mean. Both were assumed to be lognormal distributions. The lower mode corresponds to permeability estimates for intact cement [4], while the higher mode corresponds to an assumed value for wells that have material degradation, micro-annuli, or other imperfections. Injection was assumed to take place for a characteristic period of 30 years, followed by redistribution.

While there are many interesting aspects to this problem, herein we will point out only two of them. First, the simulations with more than 500 wells, covering an area of 900 km^2, and involving 13 layers in the vertical, can be computed on a single-processor desktop personal computer in about 2 hours of computing time to simulate 30 years of injection and 30 years of post-injection redistribution. This means that the model allows for the possibility of Monte Carlo analyses, wherein hundreds or thousands of simulations can be run to study probabilistic responses of the system, and to study the sensitivity of the system response to changes in the input parameters. Second, as an example of the kinds of information that can be obtained, we show in Figure 4 a sequence of plots showing the amount of CO_2 that accumulates, via secondary plumes, in the first permeable layer above the injection formation. As time increases, more of the existing wells are contacted by the injection plume, and the amount of mass leaking along the wells and into the formation above the injection formation increases with increasing time. Similar calculations are performed for all layers in the system, as well as for leakage that continues to flow upward along the wells (as opposed to flowing into intervening layers to form secondary plumes).

Conclusions

We have developed a set of semi-analytical solutions that, taken together, provide a model for CO_2 injection in deep saline aquifers and subsequent leakage along existing wells into overlying formations. The model applies to systems with many wells, and with many layers, over domains of large areal extent. The computational efficiency of the semi-analytical approach allows for large numbers of simulations to be performed, and, therefore, permits probabilistic analyses to be performed. Such a probabilistic approach can provide quantitative estimates and bounds on leakage along wells, fits well into overall risk assessment models, and can aid in the construction of regulatory frameworks for CO_2 injection and leakage.



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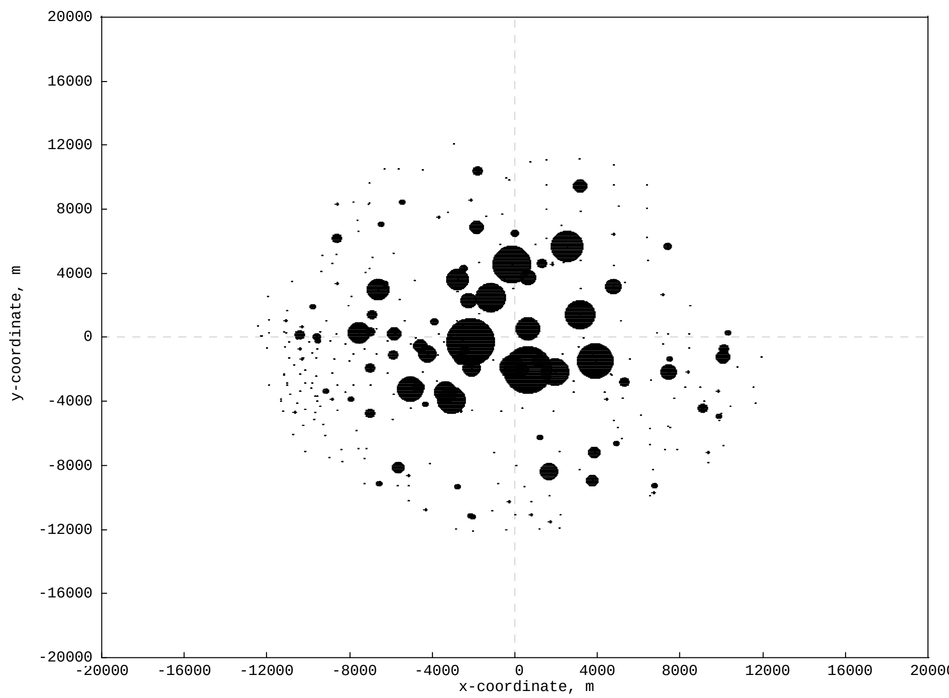

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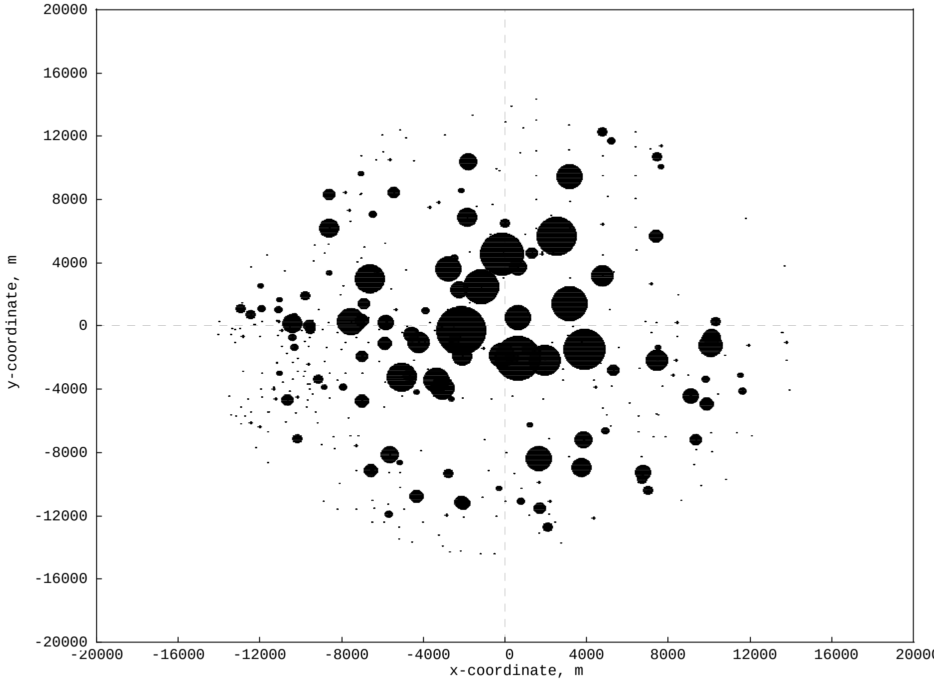

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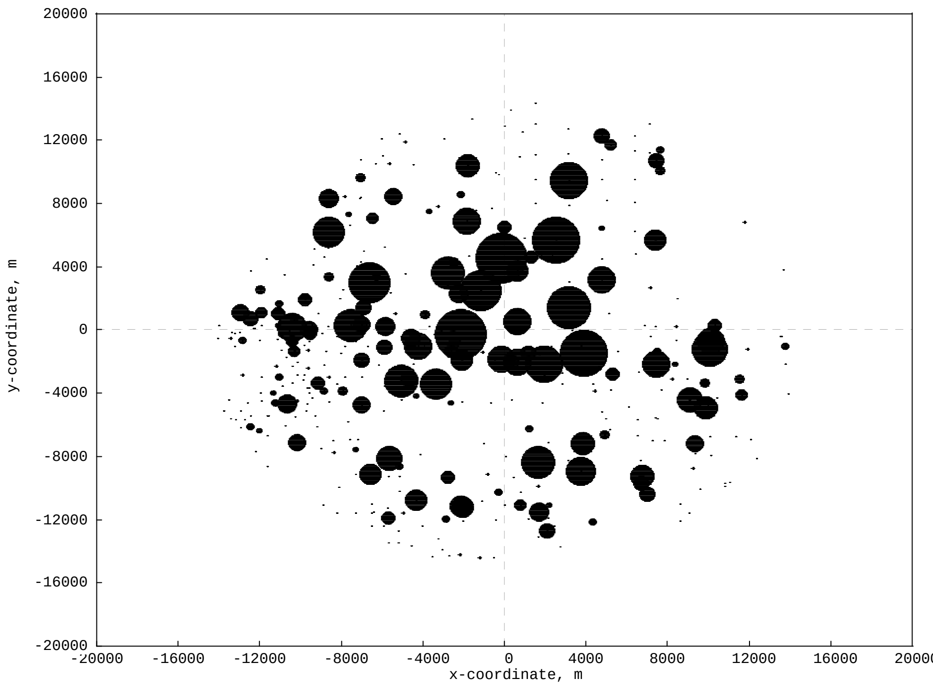

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FIGURE 4: Representation of the areal domain of the model, showing the spatial location and the relative amounts of CO_2 in the first permeable layer above the injection layer, after (a) 10 years, (b) 20 years, (c) 30 years, and (d) 60 years, for a particular realization of well permeabilities generated from the bi-modal distribution of permeability.

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