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Basin-Scale Hydrologic Impacts of CO₂ Storage: Regulatory and Capacity Implications

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Abstract

Industrial-scale injection of CO₂ into saline sedimentary basins will cause large-scale fluid pressurization and migration of native brines, which may affect valuable groundwater resources overlying the deep sequestration reservoirs. In this paper, we discuss how such basin-scale hydrologic impacts can (1) affect regulation of CO₂ storage projects and (2) may reduce current storage capacity estimates. Our assessment arises from a hypothetical future carbon sequestration scenario in the Illinois Basin, which involves twenty individual CO₂ storage projects in a core injection area suitable for long-term storage. Each project is assumed to inject five million tonnes of CO₂ per year for 50 years. A regional-scale three-dimensional simulation model was developed for the Illinois Basin that captures both the local-scale CO₂-brine flow processes and the large-scale groundwater flow patterns in response to CO₂ storage. The far-field pressure buildup predicted for this selected sequestration scenario suggests that (1) the area that needs to be characterized in a permitting process may comprise a very large region within the basin if reservoir pressurization is considered, and (2) permits cannot be granted on a single-site basis alone because the near- and far-field hydrologic response may be affected by interference between individual sites. Our results also support recent studies in that environmental concerns related to near-field and far-field pressure buildup may be a limiting factor on CO₂ storage capacity. In other words, estimates of storage capacity, if solely based on the effective pore volume available for safe trapping of CO₂, may have to be revised based on assessments of pressure perturbations and their potential impact on caprock integrity and groundwater resources, respectively. We finally discuss some of the challenges in making reliable predictions of large-scale hydrologic impacts related to CO₂ sequestration projects.

1. Introduction

Geologic carbon sequestration (GCS) in deep formations (e.g., saline aquifers, oil and gas reservoirs, and coalbeds) has drawn increasing consideration as a promising method to mitigate CO₂ emissions and associated climate change (Holloway, 1996; Gale, 2004; IPCC, 2005; Hepple and Benson, 2005). The amounts of CO₂ that would need to be injected and stored underground to make a noticeable impact on atmospheric emissions are very large. Releases of anthropogenic CO₂ into the atmosphere is currently almost 30 Gt (billion metric tonnes) per year. At typical *in situ* densities of stored CO₂, the corresponding fluid volume would be about eight times larger than the current annual world oil production. This means that geologic storage of just 15% of the anthropogenic CO₂ emission would require a fluid handling system larger than that in place for world oil production.

By far the greatest storage capacity is in saline aquifers (Dooley et al., 2004), and our discussion will focus primarily on CO₂ storage in saline formations. Injection of CO₂ into deep saline aquifers will impact subsurface volumes much larger than CO₂ plumes. An industrial-scale CO₂ storage project for a large coal-fired power plant of 1,000 MWe generation capacity will generate, over a typical lifetime, a subsurface plume with linear dimensions of order 10 km or more, while pressurization of more than 1 bar would occur over basin-scale regions with dimensions of order 100 km and more (Pruess et al., 2003). Such large-scale pressure changes may have environmental impacts on shallow groundwater resources, i.e., causing water table rise, increasing rates of discharge into lakes or streams, and/or mixing leaked native brine into drinking water aquifers

(Bergman and Winter, 1995). The level of impact depends mainly on the magnitude and extent of pressure buildup in a deep storage formation and hydraulic communications with overlying freshwater aquifers (Birkholzer et al., 2009).

One scenario where freshwater aquifers could be impacted is CO₂ injection into a storage formation that extends updip to form a drinking water resource used for domestic or commercial water supply (Nicot, 2008). Freshwater resources may also be affected if high-permeability conduits such as conductive faults and abandoned boreholes provide local conduits for pressure perturbation and brine migration. In addition, the sealing layers that separate deep storage formations from overlying freshwater aquifers may pinch out at some distance from injection sites, have higher permeabilities locally, and/or may be degraded geomechanically because of overpressure in the storage formations. All these would allow for increased interlayer communication. Finally, land-surface deformation or uplift is expected in response to large-scale pressure increases, which may change surface and subsurface flow patterns, even without a hydraulic direct impact of brine displacement. The reverse effect, land subsidence in response to groundwater withdrawal (e.g., for water supply, agriculture, or related to oil production), is a common problem throughout the United States (USGS, 1999).

Concerns about large-scale pressure buildup and brine migration caused by industrial-scale CO₂ sequestration, and their possible environmental impacts, have been raised as early as in the 1990s (van der Meer, 1992; Bergman and Winter, 1995; Gunter et al., 1996). Since then, less emphasis has been placed on evaluating large-scale pressure

changes and understanding the fate of native brines displaced by injected CO₂. Most research on geologic storage of CO₂ has instead focused on evaluating the hydrogeological conditions under which the injected volumes of CO₂ can be safely stored, addressing issues such as the long-term efficiency of structural trapping of CO₂ under sealing units and the possibility of CO₂ leakage through faults and boreholes. The same focus has been seen in risk assessment efforts (e.g., Stenhouse et al., 2006; Pawar et al., 2006; Oldenburg et al., 2008, 2009; Stauffer et al., 2009), as well as in discussions on and recommendations for permitting frameworks. Meanwhile, estimates of regional storage capacity for CO₂ sequestration have been based on simple calculations of the fraction of total reservoir pore space available for safe trapping of CO₂ (Bradshaw et al., 2007; USDOE, 2008), making the underlying assumption of “open” formations from which native brine can easily escape laterally and make room for injected CO₂. Moreover, the field experiments of CO₂ storage to date have primarily been conducted to improve our understanding of CO₂ injectivity and migration patterns, and to test methods of monitoring and modeling of CO₂ migration (e.g., the Frio experiment as described in Hovorka et al., 2006). This focus was in part out of necessity because the injected fluid volumes have been so small, on the order of several thousand to several ten-thousand tons of CO₂, that large-scale pressure buildup was not significant.

Only recently have researchers paid more attention to evaluating the large-scale pressure responses expected for future industrial-scale carbon sequestration, in part on the basis of modeling studies for hypothetical sequestration scenarios. A simulation study of CO₂ injection into compartmentalized saline formations (Zhou et al., 2008) suggests small

storage capacity because strong pressurization occurs and geomechanical damage must be avoided. Van der Meer and Yavuz (2008) introduced the concept of “total affected space” defined as the region affected by CO₂ plume migration and brine pressurization. Both studies point out that the storage capacity in bounded reservoirs is limited by a yet-to-be-defined maximum allowable pressure increase and the compressibility of the fluids and pore space in the affected area. Birkholzer et al. (2009) modeled CO₂ migration and pressure response in an idealized, laterally open groundwater system, comprising a sequence of laterally extensive aquifers and aquitards (sealing units) that extend from the deep saline storage formation to the uppermost freshwater aquifers. Based on the results from a variety of sensitivity cases, the authors concluded that the hydraulic characteristics of sealing units strongly affect the lateral and vertical volumes affected by pressure buildup.

Nicot (2008) employed a single-phase flow model to simulate the regional-scale brine flow processes in response to hypothetical future CO₂ sequestration in the Texas Gulf Coast Basin, approximating the injection of CO₂ by adding equivalent volumes of saline water. Built on a calibrated regional-scale groundwater flow model, the single-phase flow model reasonably represents the far-field processes and basin-scale impacts, without accounting for local two-phase CO₂-brine flow and variable density effects (Nicot et al., 2008a). Yamamoto et al. (2008) reported on a high-performance multi-million gridblock model capable of evaluating local CO₂-brine flow processes together with large-scale groundwater patterns, applied to a possible future CO₂ storage scenario in the Tokyo Bay, Japan. The above model results suggest that the basin-scale hydrologic impacts related to

pressure buildup and brine migration may affect the way CO₂ storage projects will be regulated. These impacts may in fact be the limiting factor determining the CO₂ sequestration capacity in large sedimentary basins.

In this paper, we elaborate on the regulatory and storage capacity issues using the Illinois Basin in the midwest United States as an illustrative example. The Illinois Basin, a deep saline sedimentary basin encompassing most of Illinois, southwestern Indiana, and western Kentucky, hosts a significant number of large stationary CO₂ emitters (MGSC, 2005). If mitigation of climate change via carbon capture and storage is seriously attempted in the United States, the Illinois Basin will be one of the most important target regions for geological storage of carbon dioxide in the United States. Extensive site characterization has been completed and a large-scale field project is ongoing to demonstrate the suitability of the regionally extensive Mount Simon Sandstone as a storage formation. We developed a regional-scale three-dimensional (3-D) model for the Illinois Basin that captures both the local-scale CO₂-brine flow processes and the large-scale groundwater flow patterns in response to a hypothetical future carbon sequestration scenario, which involves twenty individual CO₂ storage sites in a core injection area suitable for long-term storage.

Section 2 introduces briefly the geologic and numerical models and describes selected prediction results. (A comprehensive paper with much more focus on the model development and detailed results is being published concurrently.) In Section 3, the model results are used to demonstrate the importance of understanding large-scale

pressure and brine migration patterns for regulating CO₂ storage projects. We furthermore point out that CO₂ storage capacity of a given basin, estimated using the effective pore volume available for safe trapping of CO₂, might have to be revised based on assessment of pressure buildup and its potential hydrologic impacts on freshwater aquifers (Section 4). We finally discuss some of the challenges in making reliable predictions of large-scale hydrologic impacts of CO₂ sequestration projects and make some tentative suggestions (Section 5).

While the model development is based on the best information currently available, we caution that the Illinois Basin study discussed here is preliminary, that some simplifications had to be made in the model design, and that considerable uncertainty regarding the large-scale geological model needs to be acknowledged. Further site characterization efforts are underway, and model predictions of hydrologic impacts may change as more details for future storage scenarios are being developed. Readers should view this paper as an attempt to illustrate the important implications of basin-scale impacts of CO₂ sequestration, using an example that may be representative of many other hydrologic basins worldwide.

2. Illinois Basin Modeling Example

The Illinois Basin region has annual CO₂ emissions of slightly over 300 Mt (million metric tonnes) from stationary sources, primarily from large coal-fired power plants (USDOE, 2008). The primary target for CO₂ storage in the region is the Mount Simon Sandstone, a deep saline formation with proven regional seals, high permeability and

porosity, and sufficient thickness (MGSC, 2005). With a large (estimated) storage capacity (USDOE, 2008), the Mount Simon is expected to host multiple sequestration sites, based on the current portfolio of industrial point sources and the projected future developments. The saline formation extends updip to form a freshwater aquifer in southern Wisconsin. In northern Illinois, the Mount Simon is overlain by the valuable and heavily used Ironton-Galesville freshwater aquifer, separated from the deeper formation by the Eau Claire regional seal. Thus, there is a concern about potential degradation of freshwater resources due to pressure buildup and brine migration in response to future deployment of CO₂ sequestration in the area.

2.1 Geologic and Numerical Model

The model domain for the Illinois Basin covers an area of roughly 570 km by 550 km (Figure 1). It includes a core injection area suitable for CO₂ storage, and a far-field area with important groundwater resources, where environmental impacts need to be assessed. The core injection area was selected based on favorable geological settings, sufficient thickness and depth, minimum distance to gas storage fields, and proximity to large stationary CO₂ sources.

In the vertical direction, the model comprises the Mount Simon Sandstone, the overlying Eau Claire sealing unit, and the upper, weathered portion of the underlying granite bedrock. The geologic model for these formations was developed using boreholes that penetrate into the Mount Simon, a few of which had been drilled down to the underlying Precambrian granite. The Mount Simon Sandstone is continuous throughout the entire

Illinois Basin, except in the southern and southwestern parts of the Basin, where Precambrian highs exist and Cambrian sediments are absent. Its thickness varies significantly (Figure 1), with a maximum of 700 m in the bowl-shaped area in the center of the basin. The top elevation of the Mount Simon dips down from very shallow parts in the north to more than 4,000 m below the mean sea level in the south, corresponding to an average slope of 8 m per 1 km (Figure 2).

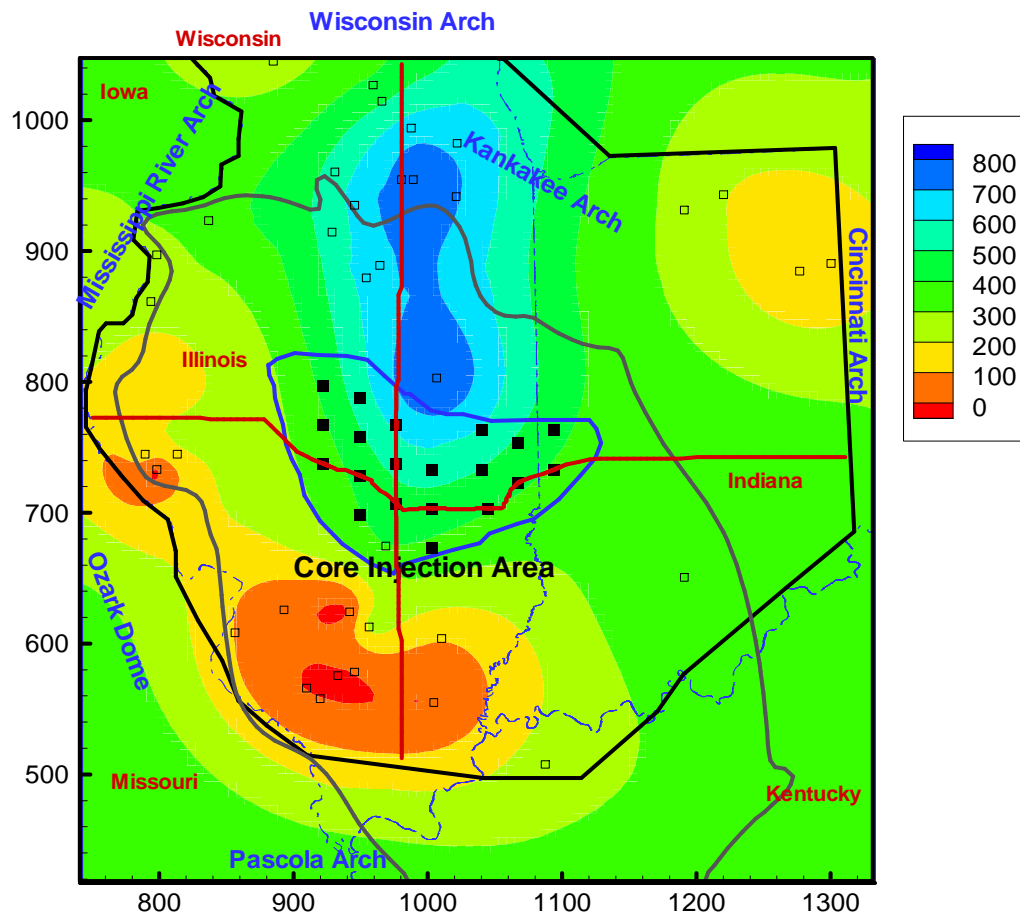


Figure 1. Thickness of the Mount Simon Sandstone (shaded contours in m). Also shown are the boundary of the model domain as a black line, the Illinois Basin boundary as a gray line, deep boreholes used for developing the geological model as hollow squares, the core-injection area as a blue line, 20 hypothetical injection sites as solid squares, and south-north and west-east cross sections (see Figure 2) as red lines. Illinois easting and northing coordinates are given in km.

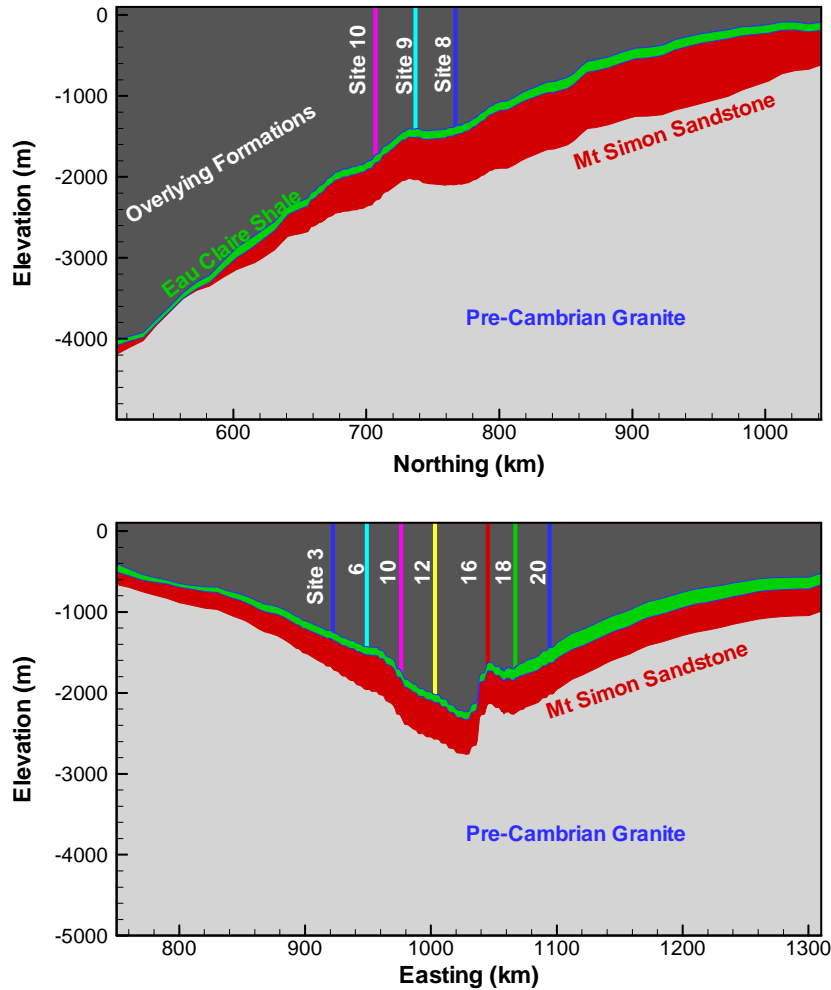


Figure 2. North-south and east-west cross sections showing simplified stratigraphy and location of CO₂ storage sites.

A three-dimensional unstructured mesh was constructed with progressive mesh refinement in the core injection area to capture details of two-phase flow and its spatial variability, using local grid refinement down to 20 m in the horizontal and 10 m in the vertical direction in the vicinity of each injection center. The entire 3-D mesh consists of over 1.2 million gridblocks and more than 3.7 million connections between them. The parallel version of the TOUGH2/ECO2N simulator was used to simulate simultaneously the plume-scale and basin-scale flow processes (Pruess et al., 1999; Pruess, 2005; Zhang

et al., 2008). A hypothetical carbon sequestration scenario was modeled, assuming twenty individual sequestration sites (spaced about 30 km apart) within the core injection area. At each site, an annual injection rate of 5 Mt CO₂ was used for an injection period of 50 years. The total injected mass per year thus represents one third of the current annual CO₂ emissions from stationary sources in the Illinois Basin region.

The rock properties and initial conditions used in the model were selected based on extensive investigation of existing literature, most of which from natural gas storage and groundwater resources development in the area. Details on the data used and the rationale for parameter selection are provided in Birkholzer et al. (2008). The key rock properties relevant to large-scale pressure propagation and brine migration are permeability, porosity, and compressibility. Permeability and porosity values near each injection site (within a 5 km radius from the injection center) were assigned based on well logs available from a small number of wells. Among these wells is the Weaber-Horn #1 well shown in Figure 3, with sonic porosity measured every 0.15 m (half foot) from an elevation of 966 to 2621 m. In order to capture plume migration details, the observed depositional variability of rock properties within the Mount Simon was incorporated into the model using 24 hydrogeologic layers. As indicated in Figure 3, CO₂ is assumed to be injected into an arkosic unit of high permeability and porosity present in the deep parts of the Mount Simon. This ensures sufficient injectivity, and takes advantage of the intervening shale-sandstone sequences of the Mount Simon, which help retard upward migration of CO₂.

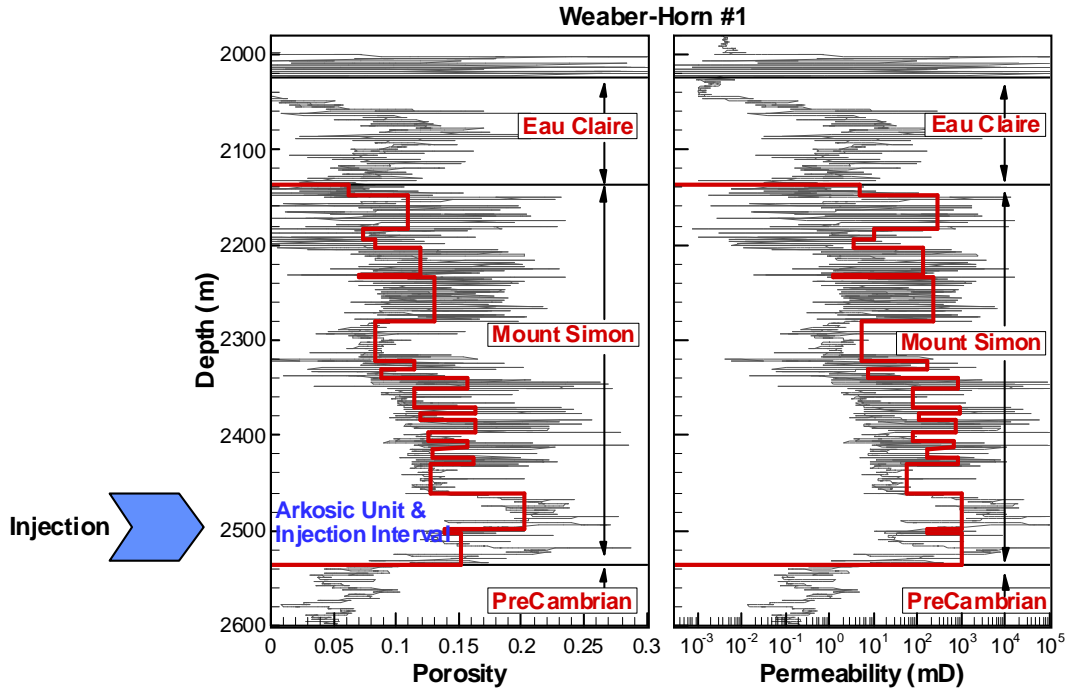


Figure3. Vertical profiles (gray lines) of (a) sonic porosity and (b) horizontal permeability (mD) for the Weaber-Horn #1 well. Also shown are average porosity and permeability values (in red lines) for the 24 Mt Simon hydrogeologic layers.

Further away from each injection site, the model uses average values of permeability and porosity for all model layers. A uniform porosity of 0.12 and a uniform permeability of 100 millidarcy were used within the core injection zone (with the exception of the injection site vicinity). Taking into account the regional trend of increasing permeability in the shallower parts of Mount Simon, we used a permeability of 500 millidarcy and a porosity of 0.12 outside of the core injection zone. The overlying Eau Claire seal has a permeability of 1 microdarcy and a porosity of 0.15; the underlying granite bedrock has a permeability of 0.1 microdarcy and a porosity of 0.05.

No direct measurements of formation compressibility were available for the Mount Simon Sandstone in the region. Therefore, we back-calculated a compressibility value of

$3.71 \times 10^{-10} \text{ Pa}^{-1}$ based on a pumping test conducted in the Hudson natural gas storage field in 1969 (ISWS and Hittman Associates, 1973; Visocky et al., 1985). This value, quite reasonable for consolidated sandstones, was used throughout the model domain. The parameters needed to describe the CO₂-brine two-phase flow system were based on Doughty et al. (2008).

Vertical profiles of *in situ* temperature and salinity were available from several temperature and salinity logs available in the area. On the basis of these profiles, an equilibrium (or hydrostatic) condition was simulated, and the resulting distributions of pressure, salinity, and temperature were used as initial conditions for the prediction of the basin-scale environmental impacts of CO₂ injection and storage. Fixed pressure, temperature, and salinity conditions were set for the lateral model boundaries. The top of the Eau Claire seal also has fixed boundary conditions to allow displaced water to flow upward and out of the model domain. The bottom boundary underlying the weathered portion of the granite is assumed to be impervious.

2.2 Model Results

Illustrative model results showing the characteristics of individual CO₂ plumes after 50 years of continuous injection are presented in Figure 4. The maximum size of CO₂ plumes, on the order of 6 to 8 km, is smaller than the lateral separation of about 30 km between different injection sites, suggesting that merging of plumes would only occur after very long times, if at all. The close-up view in the vertical cross section highlights the variability of CO₂ saturation and how it relates to the internal layering and

permeability differences within the Mount Simon. In addition to the local heterogeneity structure, the shape of CO₂ plumes is affected by the thickness of the Mount Simon and the slope of the structural surfaces, while pressure interference from neighboring injection sites has evidently little effect on plume shape.

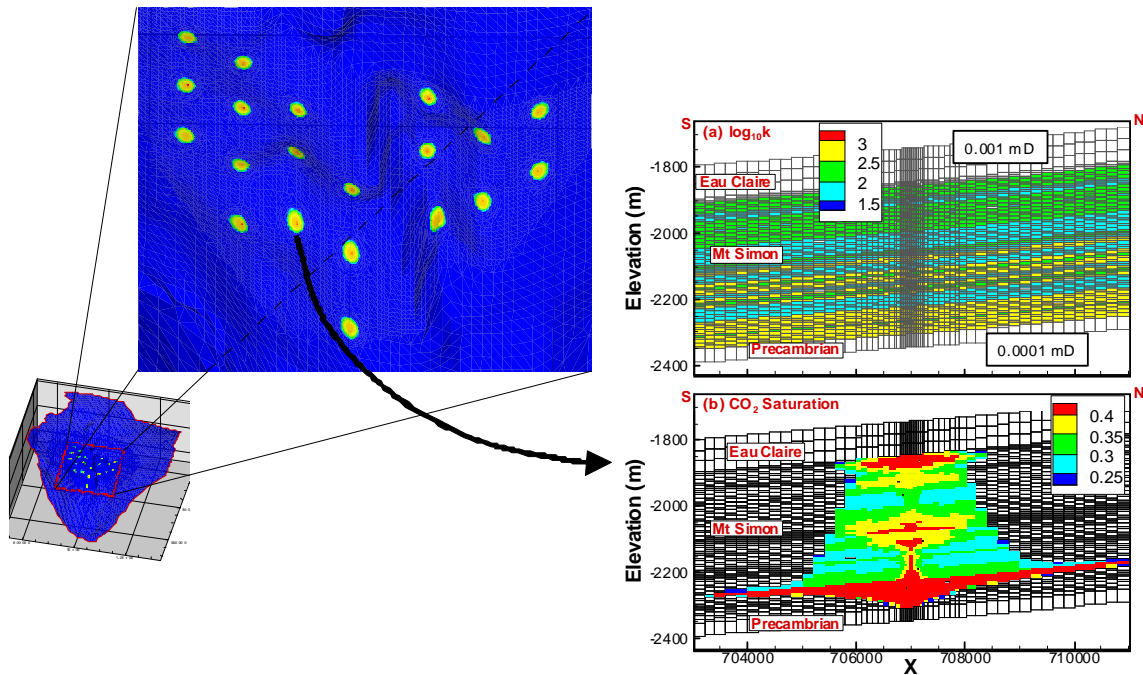


Figure 4. Graph on left shows contours of CO₂ saturation at 50 years of injection at elevation of maximum plume extent. Graphs on right show (a) vertical permeability field (in millidarcy), and (b) CO₂ saturation in a south-north cross section for a selected injection site.

The details of CO₂ saturation evident in Figure 4 emphasize the importance of local mesh refinement to resolve smaller-scale processes, such as structural trapping from internal layering. Overall, our modeling results suggest favorable conditions for safe storage and effective trapping of CO₂, including the thick arkosic unit of high porosity and permeability with sufficient injectivity at the bottom of the Mt Simon, extensive layering

with shaly and sandy deposits in the middle and upper portions of the Mt Simon, and a thick, low-permeability Eau Claire seal for ultimate and permanent structural trapping.

Figure 5 shows the simulated pressure buildup (in bar) at the top of the Mount Simon at 10, 50 (end of injection period), 100, and 200 years after start of injection. After 10 years, a continuous region with pressure increases of 10 bar or more has evolved in the core injection area, indicating strong pressure interference between different storage sites located at distances of 30 kilometers or more. After 50 years of injection, the pressure buildup in the core injection area has increased to between 20 and 30 bar, with peak values above 40 bar observed near the injection centers. While this is a considerable pressurization over a large region (of approximately 15,000 km²), it does not constitute an immediate concern with respect to geomechanical damage and caprock integrity, as the pressure increase is less than the regulated maximum value (above which fracturing of the formation may be expected). However, with respect to the far-field impact of CO₂ injection and storage, pressure changes propagate very far, as much as 150 to 200 km beyond the core injection area reaching the boundaries of the model domain. After 50 years of injection, pressure buildup is on the order of 1 to 2 bar in some parts of northern Illinois. While this pressure buildup is not likely to impact the freshwater resources within the Mount Simon (located much further north outside of the model domain), the potential hydrologic impact on overlying groundwater regimes requires additional evaluation. After CO₂ injection ends, the pressure buildup in the core injection area decreases quickly to moderate values around 5-10 bar, while the far-field pressure response continues to increase and expand (compare the 50 and 100 year frames in Figure

5). With time, the system continues to slowly progress towards a new quasi-equilibrated state, with pressures eventually returning to hydrostatic conditions, long after the end of the injection period.

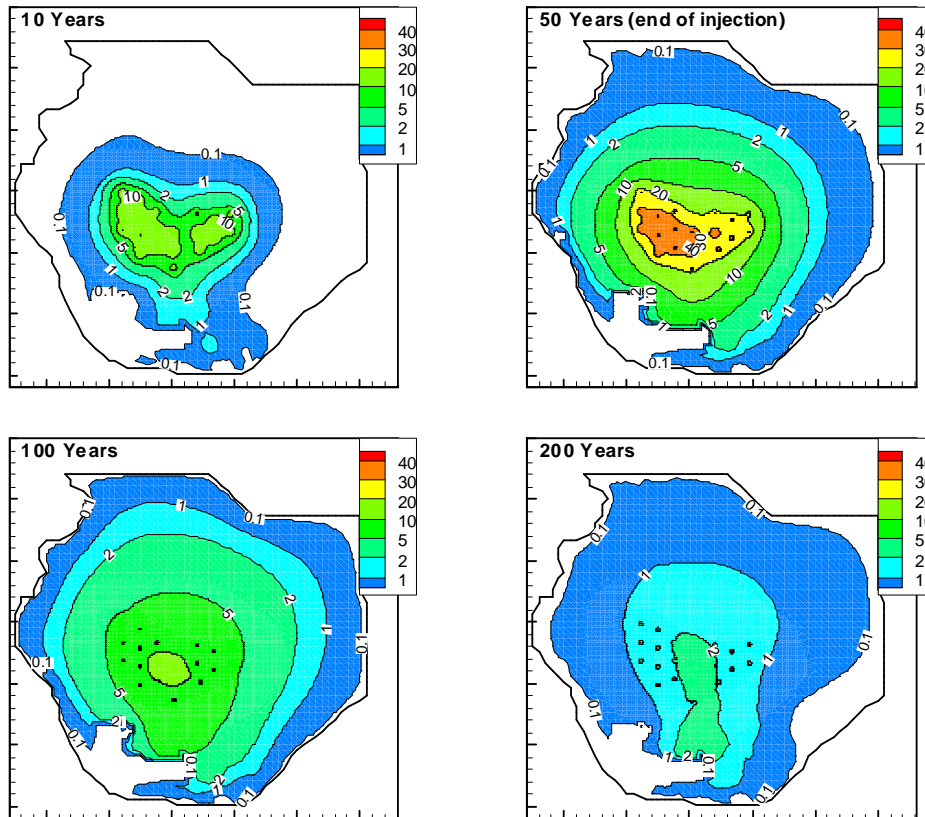


Figure 5. Contours of pressure increase (in bar) at the top of the Mount Simon Sandstone at 10 and 50 years (after start of injection) during the 50-year injection period, and 100 and 200 years during the post-injection period. The pressure cut-off value is 0.1 bar (i.e., pressure buildup below 0.1 bar is not colored).

In comparison with the magnitude and extent of pressure buildup, the changes in salinity experienced in the subsurface as a result of lateral migration of brine are very small, posing no direct threat to groundwater quality. However, salinity issues could become a concern if deep saline water from the Mount Simon was pushed upward into overlying

aquifers via localized pathways, such as conductive faults or open boreholes, which are currently not included in the model. Also not accounted for in the model is the variable sand content in the Eau Claire seal. It was suggested that the Eau Claire seal may have higher sand content (and thus locally higher permeability) in northern Illinois, which could allow brine to be pushed towards the groundwater pumping wells in the overlying Ironton-Galesville aquifer. Further studies would be needed to evaluate whether the predicted pressure change in the Mount Simon pose a threat to local groundwater resources because they may induce localized upward migration of brine.

Figure 6 demonstrates how the additional CO₂ fluid volumes injected into the basin are accommodated by two transient processes: (1) pressure-driven compressibility of the brine and the formation, and (2) brine leaving the model domain via the lateral and vertical boundaries. The total CO₂ volume in phase almost linearly increases during the injection period to a maximum value of about 5.2 billion m³. After injection stops, the total volume reduces slightly with time, reflecting the net effect of two counteracting transient processes: more CO₂ dissolves into the brine, while pressure reduction causes phase CO₂ to expand slightly. At all times, the total CO₂ volume in phase equals the added contributions of (1) the pore volume made available by pore and brine compressibility, and (2) the cumulative volume of brine released at the system boundaries. Compressibility effects dominate during the injection phase and the early post-injection phase, consistent with the observed pressure trends. Notice that formation compressibility and brine compressibility each contribute about 50% of the total

compressibility effect. Brine compressibility is $3.38 \times 10^{-10} \text{ Pa}^{-1}$ at average pressure and temperature conditions, while the selected formation compressibility is $3.71 \times 10^{-10} \text{ Pa}^{-1}$.

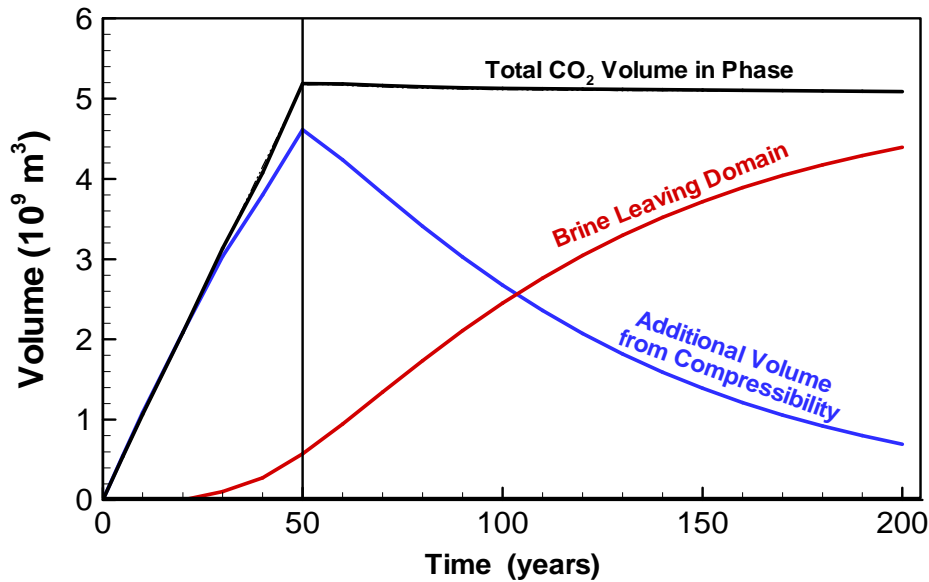


Figure 6. Evolution of volumetric fluid balance for the entire model domain, showing total CO₂ volume in phase versus fate of displaced brine. The additional fluid volumes injected into the model domain is in part accommodated by the compressibility of the brine, the injection formation, and the confining layers (blue line). Another significant fraction is contributed by brine leaving the model domain via the lateral and vertical boundaries (red line).

As the system slowly progresses towards a quasi-equilibrated state, with overpressure eventually reducing to hydrostatic (and compressibility effects becoming negligible), a volume of fluid close to the injected volume of CO₂ must egress from the model domain (Nicot, 2008). At 50 years (end of injection), the cumulative volume of brine released at the boundaries accounts for about 10% of the total CO₂ volume; at 200 years, it accounts for about 85%. Fluids leave the model domain both via the lateral boundary (into other surrounding basins) and the top boundary (into overlying aquifers). At early times (up to 50 years), brine flow out of the model domain occurs almost exclusively into overlying

aquifers, as pressure effects have not reached the lateral boundaries yet. Later, the majority of brine release occurs laterally into neighboring basins. Notice that these releases have very small lateral and vertical fluid flow velocities, typical of natural groundwater flows in deep basins (Birkholzer et al., 2009). These small velocities translate into large fluid volumes of displaced fluid only because they occur over very large areas. The small migration distances of saline water associated with these boundary flow velocities should, in most cases, not constitute a concern for groundwater resources.

3. Regulatory Implications

While the regulatory environment for geologic carbon sequestration projects is still evolving, it is clear that one aspect of permitting is the protection of valuable groundwater resources. Since groundwater quality can be affected by intrusion of CO₂ as well as by intrusion of brackish water, the permitting requirements will need to include some assessment of CO₂ leakage risk as well as some assessment of large-scale pressure buildup and associated potential for brine migration. The United States Environmental Protection Agency (USEPA) has recently developed a draft regulation for geologic carbon sequestration under the Safe Drinking Water Act (SDWA), its main focus being the protection of underground sources of drinking water from injection-related activities (USEPA, 2008). Most elements of the proposed rule are based on the existing framework of the Underground Injection Control (UIC) program, which regulates injection of hazardous and non-hazardous fluids, injection related to oil and gas production, injection related to solution mining operations, and some other types of injection operations.

USEPA requires in its proposed rule that an applicant for a permit defines an Area of Review in which all penetrations intersecting the injection formation and confining units must be identified. The purpose is to determine the presence of features such as faults, fractures, and artificial penetrations, through which significant amounts of injected fluid could move into freshwater aquifers or displace native fluids into freshwater aquifers. It is acknowledged in the draft rule that “the CO₂ plume and pressure front associated with a full-scale geologic sequestration project will be much larger than for other types of UIC operations, potentially encompassing many square miles..... It is also possible that multiple owners or operators will be injecting CO₂ into formations that are hydraulically connected, and thus the elevated pressure may intersect or interfere with each other.” USEPA thus realizes that an Area of Review (1) can be extremely large and (2) is likely to be affected by intersecting pressure perturbations in a multiple-site scenario.

The example predictions of basin-wide pressure illustrated in Figure 5 clearly demonstrate the two points made above. Assuming that a threshold value of pressure increase can be defined to delineate the Area of Review and using reasonable thresholds of about 5 and 0.5 bar (the basis of which will be discussed later in this paper), the Area of Review in our Illinois Basin sequestration scenario would encompass the entire center region of the basin, roughly 300 km by 300 km (for 5 bar at 50 years) and 500 km by 500 km (0.5 bar at 50 years), respectively. In other words, areas exceeding 100,000 km² would have to be characterized for conductive features and artificial penetrations would have to be tested for proper completion and plugging. This task would likely exceed the capacity and willingness of any single operator in the basin, even more so as the enormous size of

the Area of Review in the Illinois Basin would be the composite result of many other storage sites operating simultaneously. Owners or operators would likely point out that their individual contribution to the Area of Review extent is only a fraction of the composite Area of Review.

The question arises how these regional impacts of geologic sequestration, with multiple storage sites in a given basin, can be effectively regulated. One possibility could be to regulate under a “first come, first serve” principle, where early applicants in a basin would have the advantage of delineating their Area of Review without consideration of other possible storage operations. Later applicants would have to develop their permitting case under consideration of the pressure impacts of all ongoing or approved operations in the region. The Area of Review for these applicants would be defined by the additional pressure increase expected from the new storage project, determination of which is not an easy task for an applicant because current and future impacts from all other operation need to be known. Also, later applicants might have higher operational costs because they may need to inject into a pressurized formation. The “first come, first serve” principle would favor early projects, a possible incentive for accelerated implementation of carbon capture and storage.

An alternative, more coordinated approach to regulating basin-scale multiple-site CO₂ sequestration is the hierarchical permitting model recently proposed by Nicot and Duncan (2008). These authors suggest two permitting levels: The first level (referred to as general permit) would involve an overarching federal or state agency to develop regional assess-

ments of large brine reservoirs with the goal of characterizing them to the point that they are “sequestration ready”. The second level would involve permit applications for individual sites, with the expectation that (1) the burden faced by an applicant would be less because regional assessments have already been conducted, and (2) the permitting process for each site would be reviewed under the umbrella of a coordinated regional permit.

Expanding on Nicot and Duncan (2008), we suggest a general permit should handle all Area-of-Review tasks related to far-field pressure change and brine migration, while a single-site permit would focus on the local area near the projected site, including the area of the CO₂ plume and some yet-to-be defined area beyond the plume extent where pressure impacts are highest. In our Illinois Basin example, individual applicants might be focusing on the core injection area shown in Figure 1, while the responsible agency for a regional permit would conduct the necessary characterization and corrective action (e.g., plugging of improperly completed wells) activities outside of this core area. The responsible agency would also (1) oversee efforts to build reliable basin-scale simulation models for the region, (2) predict the large-scale hydrologic impacts for possible future sequestration scenarios in the region, (3) define the size of the Area of Review, and (4) estimate the maximum storage capacity in the basin based on the projected environmental impacts. The simulation model would be periodically re-evaluated as more storage projects go online and more monitoring data become available. Based on model predictions, new site applications would be evaluated and coordinated in the context of other existing and planned operations.

Of crucial importance for permitting of large storage projects is the question as to how the size of an Area of Review should be determined, in particular with respect to the hydrologic consequences of large-scale pressure buildup and possible brine migration into groundwater resources. While there is a general consensus that the region of maximum future CO₂ plume extent needs to be well characterized, it is not clear at present how handle the much larger region of pressure impact in a site evaluation process. Can the size of an Area of Review be determined based on a threshold value of pressure buildup and, if so, how can this value be determined? While the draft regulation introduced by USEPA currently provides no guidance on this matter, one possible approach could be based on the existing framework of the Underground Injection Control (UIC) program. There, the Area of Review is computed as the region where the pressure increase experienced at any time would be able to lift saline formation water through a potentially existing open borehole to the bottom of an overlying freshwater aquifer. Because the brine being pushed upward has a higher density than the borehole fluid it displaces, upward migration of brine can only be sustained when the pressure increase in the formation exceeds a minimum value, which is mostly determined by the vertical distance and the initial density profile in the borehole. Nicot et al. (2008b) presented a method for calculating this minimum value and applied it to case studies from a site in the Central Valley in California and two sites in the Texas Gulf Coast region. Pressure threshold values ranged from 0.58 bar for the Central Valley case up to 5.6 bar for the Texas Gulf Coast cases, the difference mostly caused by the much higher salinity of the deep brines in the latter examples. The calculations assume that the pressure profiles are initially hydrostatic, a condition that may or may not be appropriate.

One may express concern that Area-of-Review estimates based on the potential existence of completely unplugged boreholes may be too conservative, particular in regions not or not strongly affected by a long history of oil and gas exploration. Such estimates can be extremely large, as would be the case in our Illinois Basin example. Depending on the site conditions, other conduits for brine migration into freshwater aquifers may be more relevant, such as conductive faults or other caprock imperfections. In the Illinois Basin, the relatively few deep boreholes penetrating down to the Mount Simon formations may not pose a threat at all as they are likely to be properly plugged, whereas a possibly higher permeability of the Eau Claire seal in the northern part of the basin could allow brine to be pushed towards the groundwater pumping wells in the overlying Ironton-Galesville aquifer. We believe that the size of an Area of Review cannot be determined from a generic one-size-fits-all approach. Rather, the detailed basin- and site-specific conditions, and the vulnerabilities of potential environmental receptors to brine leakage, need to be accounted for in any Area of Review definition. We also believe that the site characterization requirements for the region of maximum future CO₂ plume extent would be different from the requirements imposed on characterizing the much larger region of pressure impact, as the driving forces for leakage of CO₂ versus brine are different, and so may be the possible environmental impacts.

4. Capacity Implications

High-level estimates of regional or global storage capacity for CO₂ sequestration in saline formations have typically been based on simple calculations of the fraction of the total reservoir pore space available for safe storage of CO₂ (Bradshaw et al., 2007; USDOE,

2008). Such capacity assessments start with delineating reservoirs in a basin or region suitable for deep geologic storage (sufficient depth and injectivity), followed by calculating the total storage capacity as a fixed fraction of the reservoir pore volume that can be filled with safely trapped CO₂. In saline formations, the suggested estimates for this fraction, often referred to as the storage efficiency factor, have been on the order of 1% to 4% (e.g., Koide et al., 1992; USDOE, 2008; van der Meer and Yavuz, 2008). Other researchers have calculated storage potential based on the solubility potential of CO₂ (e.g., Bachu and Adams, 2003). In either way, issues related to pressure buildup or brine migration have not been considered, i.e., there is an implicit assumption that the storage capacity is not constrained by pressure buildup (and brine migration) and associated impacts on the environment.

As pointed out by Bradshaw et al. (2007), simplistic capacity estimates at the regional or global level can be highly variable and in some instances contradictory, due to the different trapping mechanisms that can occur, and the highly variable nature of geologic settings. These authors suggest that a consistent set of guidelines needs to be developed with clear definitions, rules, and best practices. We strongly agree with Bradshaw et al. (2007), but emphasize the need to base capacity estimates not just on formation suitability with respect to injectivity and trapping of CO₂, but also on the possible basin-scale hydrologic impacts caused by adding large volumes of fluids. Our work presented here, as well as recent studies reported in Zhou et al. (2008), Nicot (2008), Birkholzer et al. (2009), and van der Meer and Yavuz (2008), suggest clearly that environmental

concerns related to large-scale pressure buildup may be the limiting factor in carbon dioxide sequestration capacity.

To illustrate the potential impact of pressure-related capacity constraints, let us compare our hypothetical future injection scenario studied in Section 2 with the current high-level capacity estimates for the Mount Simon, which were based on pore volume, trapping considerations, and pore occupancy limits. The annual rate of CO₂ injected in our simulation scenario is 100 Mt, about one-third of the total CO₂ emissions from current large point sources in the Illinois Basin, and the total injected fluid mass after 50 years is 5,000 Mt. In contrast, the total estimated CO₂ storage capacity for the Mount Simon Sandstone, calculated as a fraction of the total reservoir pore space in suitable parts of the Mount Simon, ranges from 27,000 to 109,000 Mt CO₂ (USDOE, 2008). Thus, the stored CO₂ volume in our simulation scenario corresponds to 18.5% of the lower bound and 4.6% of the upper bound of this range. If CO₂ injection were to continue at the assumed injection rate for a much longer period (or if CO₂ was injected at a higher annual rate), such that the estimated storage capacity was fully utilized, the pressure buildup would be much stronger and extend over a much larger area than seen in Figure 5. While we have not simulated the expected subsurface conditions for such a full-capacity storage scenario, we believe that storage of 27,000 (or more) Mt of CO₂ in the Illinois Basin would be difficult because of (1) strong pressure buildup within the core injection area, which would jeopardize caprock integrity, and (2) moderate pressure buildup on the basin scale, which might have environmental impact on freshwater aquifers in northern Illinois or on neighboring basins.

With respect to caprock integrity, the maximum pressure increase in the current simulation scenario is about 30 to 40 bar near the center of individual storage sites, which corresponds to an average fractional pressure buildup, defined as the ratio of pressure increase to pre-injection pressure, of 0.25. (Introduction of additional injection wells at each site may have some local effects, but would not significantly reduce the overall pressure buildup in the core injection area because of the strong interference between individual storage projects.) This value of 0.25 is less than the regulated fractional pressure increase of 0.65 used in the region. If a value of 0.65 (or a maximum pressure buildup of up to 90 bar) is used and a quasi-linear relationship between injection rate and pressure buildup (Zhou et al., 2009) is considered, the total injection volume assumed in our simulation scenario could be increased from 5,000 to 13,000 Mt. However, regulators might be reluctant to allow fluid pressurization of such magnitude over such a large area. Also, as mentioned above, the geomechanically-constrained storage capacity of 13,000 Mt may not be achieved in case the far-field pressure buildup in the Mount Simon poses a threat to the groundwater resources in northern Illinois, a possible result of localized upward migration of brine into freshwater aquifers.

We may thus conclude that current high-level estimates of regional or global storage capacity in deep saline formations need to be revisited based on the evaluation of pressure buildup and environmental impacts, and we may expect that these estimates would have to be corrected downward in many cases. Because of the complex nature of large-scale hydrologic processes, such capacity re-evaluation needs to be site- or basin-specific; it is not conducive to generalization or quick assessment with no or limited data.

It should be noted that pressure-related capacity constraints may be relaxed by creating additional store space in the deep storage reservoirs via brine extraction. The extracted brine could be stored in appropriate overlying/underlying formations, or could be pumped to the surface and desalinated for water supply. While such pressure management schemes can provide a way around capacity limitations, their technical and economic feasibility needs to be evaluated in further studies.

5. Prediction Uncertainties

From the standpoint of fluid dynamics, brine pressurization and migration is a much simpler process than two-phase flow of CO₂-brine mixtures. The challenge for predictive modeling is not in fundamental process issues, but rather in obtaining a sufficiently detailed and realistic characterization of large subsurface volumes, in order to be able to place meaningful and reliable limits on quantities and pathways for pressure buildup and brine migration. The propagation of pressure changes in a porous medium is a function of the hydraulic diffusivity D of the formation. Hydraulic diffusivity is defined as the ratio of transmissivity to storativity, given as $D = k/(\beta\phi\mu)$, where k is formation permeability, β is compressibility of both the brine and the pore structure, ϕ is porosity, and μ is dynamic viscosity of the brine. For a given D , the propagation radius R of a pressure wave in a two-dimensional radial system with constant thickness and homogeneous properties can be approximated as $R \approx \sqrt{2Dt}$, where t is the time since injection starts (Nordbotten et al., 2004). We apply this approximate equation below to demonstrate that uncertainties in the key parameters for pressure propagation can strongly affect the extent of the pressure-affected region.

Using the formation properties chosen for the Mount Simon simulation model outside of the core injection zone (see Section 2.1), i.e., $k = 500$ millidarcy ($= 5 \times 10^{-13} \text{ m}^2$), $\beta = 7.09 \times 10^{-10} \text{ Pa}^{-1}$ (which comprises contributions from brine compressibility, $3.38 \times 10^{-10} \text{ Pa}^{-1}$, and formation compressibility, $3.71 \times 10^{-10} \text{ Pa}^{-1}$), $\phi = 0.12$, and $\mu \approx 0.0005 \text{ Pa s}$, D becomes approximately $11.7 \text{ m}^2/\text{s}$. This translates into a pressure propagation radius from the core injection zone of $R \approx 86 \text{ km}$ after 10 years and $R \approx 190 \text{ km}$ after 50 years, which is in reasonable agreement with the model predictions in Figure 5. A change in hydraulic diffusivity by one order of magnitude, arguably a reasonable uncertainty range for large-scale hydraulic properties, would translate into a change in pressure propagation radius by roughly a factor of three. In other words, if hydraulic diffusivity is smaller by a factor of 10, which could be caused by a smaller permeability, larger compressibility or porosity, or a combination thereof, the extent of the pressure-affected region outside of the core injection area would reduce from 190 km to only 60 km. This makes a considerable difference with respect to the size of the Area of Review that would have to be characterized in the case of multiple-site sequestration in the region.

Additional factors that are not well understood or hard to characterize can further increase uncertainty about large-scale hydrologic impacts, for example the possible dampening of pressure propagation across faults, the far-field effect of small-scale and intermediate-scale heterogeneity (e.g., sand-shale interbedding), or the possibility of pressure relaxation by brine flow into overlying and underlying units. Notice also that the approximate propagation distance calculated above is not a measure of the possible magnitude of the pressure perturbation. While a decrease in permeability and an increase

in compressibility have the same effect on propagation distance, the magnitude and spatial distribution of pressure changes would be very different. A smaller permeability value causes less far-field pressurization, but higher pressure buildup in the core injection area, possibly up to the point that injectivity or geomechanical damage may become a concern. While a higher compressibility value also causes less far-field pressurization, the pressure buildup in the core injection area would be reduced as well, as more storage volume per unit volume of rock is created from the same overpressure.

It is clear that a comprehensive site characterization and data review of deep saline formations on the basin scale are needed to allow for reliable prediction of regional brine pressurization and migration; i.e., the extent, geology, hydrology, and hydraulic connectivity of deep hydrologic systems needs to be well understood. It is also obvious that large CO₂ storage field experiments, such as the deployment phase tests soon to start in the United States (NETL, 2009), can be very useful for better understanding and constraining the processes and parameters driving brine pressurization. We strongly recommend making measurements of far-field brine pressurization a significant component of the monitoring strategy in these tests. However, the storage volumes achievable in such experiments, likely close to one million metric tonnes, may still be too small to allow extrapolation to the basin or regional scale. Possibly the best analog for industrial-scale carbon sequestration is industrial-scale carbon sequestration itself. In other words, the pressure monitoring conducted in the early phase of a industrial-scale project can provide valuable data for further pressure impacts during later project stages; i.e., these data would feed into periodic re-evaluation with improved prediction models.

Similarly, in a basin with multiple storage sites, data from early projects can help to reliably estimate the expected pressure impact from later projects.

6. Summary and Conclusions

We evaluated regional-scale brine pressurization and migration related to a hypothetical future carbon sequestration scenario in the Illinois Basin in the midwest United States. The area hosts a significant number of large stationary CO₂ emitters and will be one of the most important regions for geological storage of carbon dioxide in the United States. A regional-scale 3-D simulation model was developed for the Illinois Basin to capture both the local-scale CO₂-brine flow processes and the large-scale groundwater flow patterns in response to CO₂ storage. We assumed in our simulations that each of the twenty individual storage projects spread out in the center of the basin will inject 5 Mt of CO₂ annually over a time period of 50 years. The total annual injection volume of all projects corresponds to roughly one third of the current annual CO₂ emissions from stationary sources in the area. The target reservoir for storage is the Mount Simon Sandstone, a very extended saline formation with proven seals, good permeability and porosity, and sufficient thickness.

Our predictions demonstrate that multiple-site storage in the Mount Simon will result in a large continuous region with overpressure, in which the pressure perturbations from one storage site strongly interfere with other storage sites. With respect to far-field impacts, pressure changes may propagate as far as 200 km from the core injection area hosting the 20 storage sites. While this pressure buildup is not likely to impact freshwater resources

in shallow parts of the Mount Simon (located further north outside of the model domain), the potential of hydrologic and geochemical changes in the overlying groundwater regimes requires further evaluation. For example, salinity issues could become a concern if brackish water from the Mount Simon is pushed upward into overlying freshwater aquifers via possibly existing localized pathways, such as conductive faults or open boreholes.

While recognizing considerable uncertainty in our predictive model, we used the Illinois Basin study as an illustrative example to discuss some of the implications related to multiple-site CO₂ sequestration in deep saline formations. Our main conclusions and recommendations are listed below:

- Understanding the large-scale pressure buildup and brine migration patterns is extremely important when it comes to regulating CO₂ storage projects, in particular when multiple storage sites are hosted in a sedimentary basin with interconnected reservoirs. In such cases, pressure interference between individual sites will require appropriate and effective permitting approaches. Two suggestions are made in this paper, one using a “first come, first serve” principle, the other following Nicot and Duncan’s (2008) proposed hierarchical approach with a general permit for a region and site-specific permits for individual projects.
- Considering the extent of pressure propagation observed in our study, the area that needs to be characterized in a permitting process (referred to as the Area of Review in the new draft regulation proposed by USEPA) can comprise an extremely large region. The question as to how to define the size of the Area of

Review with respect to large-scale hydrologic consequences will thus be of critical importance. We believe that a one-size-fits-all approach, e.g., defining a general fixed-value pressure threshold, will not work; rather we suggest basing the Area of Review size on the detailed basin-scale conditions and the vulnerabilities of potential environmental receptors. Within the Area of Review, the site characterization requirements for the region of maximum CO₂ plume extent should be higher than those for characterizing the much larger region of pressure impact.

- Further research is needed to evaluate the possible consequences of far-field pressurization on groundwater resources, i.e., evaluating the potential for and magnitude of upward brine migration via possibly existing localized pathways, such as conductive faults or open boreholes, or analyzing the water quality changes in response to brine intrusion into freshwater aquifers.
- In deep saline formations, geomechanical and environmental concerns related to large-scale pressure buildup may be the limiting factor for sequestration capacity. We believe that current estimates of storage capacity, which are typically based on the effective pore volume available for safe trapping of CO₂, need to be revisited on the basis of site- or basin-specific assessments of pressure buildup and their potential impacts on freshwater aquifers. Creative pressure management schemes via brine extraction (and subsequent re-injection into other formations, or desalinization and use for water supply) could provide an engineering solution in cases where storage capacity is limited by pressure buildup, but further studies on feasibility and economics are necessary.

- Considering the importance of large-scale predictions of hydrologic impacts in response to CO₂ storage, we recognize the usefulness of upcoming large field tests for better understanding the relevant processes and parameters. Far-field measurements of brine pressurization should be included, as an important monitoring component, in these tests.

It is important to assess (and regulate) the potential environmental impacts of GCS in the context of other anthropogenic influences affecting our groundwater resources. For example, excessive pumping of groundwater resources for municipal water supply and agricultural uses has caused widespread aquifer drawdown and salinity increases in many areas in the United States. In the Chicago metropolitan area, heavy groundwater pumping in northern Illinois induced drawdown of up to 250 m during the second half of the last century, eventually pulling deeper saline waters towards some withdrawal wells. These impacts dwarf the predicted environmental consequences of geologic carbon sequestration in the area. One also needs to weigh the environmental impacts of GCS against the regional and global benefits of mitigating climate change. In other words, one needs to consider the potential environmental, socioeconomic, political, and also hydrological consequences of continued CO₂ emissions in a business-as-usual climate scenario.

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