A Methodology for Monetizing Basin-Scale Leakage Risk and Stakeholder Impacts

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Abstract

Carbon dioxide (CO₂) capture and storage involves injecting CO₂ into permeable geologic reservoirs. Candidate reservoirs will be overlain by an impervious caprock, but CO₂ or brine may leak through this caprock via natural or manmade pathways into overlying units. Such leakage will incur multiple costs to a variety of stakeholders, as mobile fluids may interact with other subsurface activities, reach groundwater, or possibly escape from the surface. We summarize a methodology to monetize leakage risk throughout a basin, based on simulations of fluid flow, subsurface data, and estimates of costs triggered by leakage. We apply this methodology to two injection locations in the Michigan (U.S.A.) Sedimentary Basin, and show that leakage risk is site-specific and may change priorities for selecting CO₂ storage sites, depending on its siting relative to leakage pathways and other subsurface activities.

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1. Introduction

Carbon [dioxide] capture and storage (CCS) is a process that would involve injecting carbon dioxide (CO₂) into geologic reservoirs. CO₂ is to be “stored” in these reservoirs for hundreds or thousands of years, but the integrity of the seal—-a relatively impermeable caprock—may not be perfect, and injected CO₂, or the brine it displaces, may leak through wells, wellbores, existing faults, or fracture networks. Such leakage may incur multiple costs if the mobile fluids interfere with other subsurface activities—water production, energy production, energy storage, and waste disposal—or migrate to the surface (Figure 1). Since many different activities could be affected by leakage, many different stakeholder
groups could be affected by leakage events and potential costs or damages could arise from interference with these activities. As a result, site selection for potential CO\textsubscript{2} storage reservoirs must include assessments of leakage risk within a three-dimensional proximity of where CO\textsubscript{2} is being injected and how potential monetary consequences of leakage could differ among stakeholders. Determinations of leakage risk for multiple possible injection locations within a basin are therefore necessary in order to prioritize options for CO\textsubscript{2} storage.

Figure 1: CO\textsubscript{2} Injection and Storage Reservoir Leakage amidst Past and Present Subsurface Activities – Injected CO\textsubscript{2} or displaced brine may leak out of the storage reservoir through leakage pathways (wells are shown here). Such leakage triggers costs and may interfere with other activities, contaminate groundwater (USDW), or migrate to the surface (not shown).

We present a methodology to probabilistically assess leakage risk for geologic CO\textsubscript{2} storage, and demonstrate that methodology on two potential injection locations in the Michigan Sedimentary Basin. This methodology comprises the RISCS (Risk Interference Subsurface CO\textsubscript{2} Storage) model, which monetizes leakage risk across a broad range of relevant stakeholders. If CO\textsubscript{2} or brine leaks from the injection formation, interferes with other subsurface activities, migrates into groundwater, or reaches the surface, RISCS monetizes this risk and spatially quantifies how it could differ in magnitude and location across ten different stakeholder groups. We show that leakage risk is site-specific, depending on how CO\textsubscript{2} injection is sited relative to leakage pathways and other subsurface activities.

2. Basin Scale Leakage Risk Assessment: Methodology and Example in the Michigan Sedimentary Basin

Determining the potential for a basin to store CO\textsubscript{2} requires that the assessment of multiple potential injection locations. The Michigan Sedimentary Basin is estimated to have up to 15 GtCO\textsubscript{2} storage capacity [1] partitioned between the St. Peter and Mt. Simon formations—two of the basin’s sixteen
major hydrostratigraphic units (Table 1). We apply the RISCS model on two potential injection locations in the Michigan Sedimentary Basin. The results we present indicate that leakage risk as a function of the three-dimensional proximity to leakage pathways and other subsurface activities.

Figure 2: Michigan Sedimentary Basin and Chosen Injection Locations - Two CO₂ Injection locations (11, 17) and Nine Locations (A-I) where CO₂ or Brine May Leak through Existing Wells into the Overlying Galesville Aquifer.

2.1. Risk Interference of Subsurface CO₂ Storage (RISCS) Model

Risk is a function of the probability of an outcome and the impact of that outcome. To monetize leakage risk, the RISCS (Risk Interference Subsurface CO₂ Storage) model [2-3] combines (1) probabilistic CO₂ and brine leakage magnitudes and spatial extents from simulations of geophysical fluid flow, (2) three-dimensional geospatial data, and (3) estimates of potential costs triggered by leakage. For (1), we use the Estimating Leakage Semi-Analytically (ELSA) model; (2) is compiled from data acquired from the United States Geologic Service (USGS) and the Michigan Department of Environmental Quality; and (3) uses the Leakage Impact Valuation (LIV) method to estimate the financial consequences of leakage. Each of these numbered items is presented next.

RISCS weights the estimated costs triggered by leakage events based on the degree to which CO₂ or brine is present outside the storage reservoir or in an area. These weights are functions of the percentage of the unit thickness that CO₂ occupies, the degree to which brine pressure is elevated above hydrostatic, and the number of leaking wells within a kilometer.

2.1.1. Estimating Leakage Semi-Analytically (ELSA) Model

ELSA simulates CO₂ injected into saline aquifers, and determines where CO₂ and displaced brine flow within the injection formation, through well leakage pathways, and in overlying aquifers and well pathways [4-5]. RISCS can run ELSA using draws from distributions for critical uncertainties (e.g.,
permeability, porosity, thickness) and numerous well leakage permeabilities. Multiple iterations using values drawn from distributions provide for probabilistic determination of the extents and magnitudes of CO₂ plumes and brine pressure perturbations. We conduct four leakage scenarios wherein we vary the permeability of existing wells the leaking wells. Existing wells are assigned leakage permeabilities of $10^{-10}$ m$^2$, $10^{-12}$ m$^2$, $10^{-14}$ m$^2$, and $10^{-16}$ m$^2$, corresponding to each of the leakage scenarios, respectively. For the application presented here, we do not iterate ELSA with values drawn from other distributions. ELSA is used to simulate 4 MtCO₂/yr injection continuously for 30 years into the Mt. Simon sandstone, 2.6 and 2.4 km underground (Location 11, and Location 17, respectively). Simulations are conducted with a 200 km radial extent, and data are recorded on a 150 km x 150 km grid at 1 km spacing. For the injection locations chosen for this analysis (11, 17), CO₂ is injected into the center of the recording grid. Consequently, data are recorded on a square grid extending out 75 km horizontally (east and west) and vertically (north and south) from the injection location.

2.1.2. Three-Dimensional Geospatial Data

Three-dimensional geospatial data locates hydrostratigraphic units and the wells that penetrate these units. These wells may serve as leakage pathways, allowing injected CO₂ or displaced brine to migrate into overlying units. Active wells locate existing subsurface activities and may be modeled as leakage pathways in the geophysical fluid flow simulations; inactive wells do not locate existing subsurface activities, but they may also be modeled as leakage pathways in the geophysical fluid flow simulations. The Michigan Sedimentary Basin contains sixteen named hydrostratigraphic units. For ELSA, the hydrostratigraphic sequence must be represented by a layer cake of permeable aquifers and impermeable aquitards. Consequently, the three-dimensional geospatial data must be appropriately combined. For the analysis presented here, high- and mixed-permeability units are combined and modeled as aquifers—except for the Prairie du Chien (low permeability in the chosen injection locations)—and low probability units are modeled as aquitards (Table 1).
Table 1: Sixteen Hydrostratigraphic Units Throughout the Michigan Basin and their Representation in ELSA for the Four Chosen Injection Locations.

<table>
<thead>
<tr>
<th>HYDROSTRATIGRAPHIC UNITS</th>
<th>ELSA SEQUENCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarternary</td>
<td>Aquifer 1</td>
</tr>
<tr>
<td>Jurassic</td>
<td>(Jurassic is absent)</td>
</tr>
<tr>
<td>Upper Pennsylvanian</td>
<td></td>
</tr>
<tr>
<td>Lower Pennsylvanian</td>
<td></td>
</tr>
<tr>
<td>Bayport-Michigan</td>
<td></td>
</tr>
<tr>
<td>Marshall</td>
<td></td>
</tr>
<tr>
<td>Devonian-Mississippian</td>
<td>Aquitard 1</td>
</tr>
<tr>
<td>Traverse-Dundee</td>
<td>Aquifer 2</td>
</tr>
<tr>
<td>Silurian-Devonian</td>
<td></td>
</tr>
<tr>
<td>Collingwood</td>
<td>Aquitard 2</td>
</tr>
<tr>
<td>Trenton-Black River</td>
<td>Aquifer 3</td>
</tr>
<tr>
<td>St. Peter</td>
<td></td>
</tr>
<tr>
<td>Prairie du Chien</td>
<td>Aquitard 3</td>
</tr>
<tr>
<td>Galesville</td>
<td>Aquifer 4</td>
</tr>
<tr>
<td>Eau Claire</td>
<td>Aquifer 4</td>
</tr>
<tr>
<td>Mt. Simon</td>
<td>Aquifer 5</td>
</tr>
<tr>
<td>Pre-Cambrian Basement</td>
<td></td>
</tr>
</tbody>
</table>

2.1.3. Leakage Impact Valuation (LIV) Method

The LIV method [6-8] is a thorough scenario-based approach to identifying the financial costs that are triggered by leakage and the stakeholders that incur these costs. LIV identifies the costs incurred by ten different stakeholders—including the injection operator and regulator, subsurface activity operator and regulator, surface residents and groundwater users, among others. Reasonably plausible storylines are developed for low- and high-cost cases for four broad classes of leakage outcomes: 1.) Leakage only; 2.) Leakage interferes with a subsurface activity; 3.) Leakage reaches an Underground Source of Drinking Water (USDW); or 4.) Leakage reaches the surface. From these storylines and leakage outcomes, multiple costs are estimated across six cost categories: Diagnostic Monitoring, Containment Activities, Environmental Remediation, Damages, Climate Compensation, and Site Closure. Estimates of costs triggered by individual leakage events in the Michigan Sedimentary Basin using the LIV method are detailed elsewhere [7], but, for Nth-of-a-kind projects, estimated costs range from $2.2M for a low-cost leakage only outcome to $154.7M for a high-cost event where CO$_2$ affects groundwater and migrates to the surface.

3. Results

Figure 3 shows the increase pressure in the brine in the bottom two aquifers—Mt. Simon and Galesville—after 30 years of continuous CO$_2$ injection. CO$_2$ injected into the Mt. Simon increases the pressure, displacing brine that then leaks along well pathways through the Eau Claire aquitard and into the overlying Galesville aquifer.
Figure 4 shows temporal risk profiles for these two locations as monetized by RISCS. The monetized values for the extreme leakage cases we present. Three leakage outcomes occur at Location 11. In year 12, a ~$30M brine leakage event occurs through well C. A ~$38M brine leakage event occurs twelve years later, through well D, and a ~$35M brine leakage event occurs two years after that, in year 26, through well I. Location 17 has more leakage events that incur more costs: two ~$40M events in years 15 and 28 (F and H, respectively), and three ~$26M events in years 20, 21, and 26 (D, G, and X, respectively). The event labeled “X” on does not occur directly as the result of leakage out of the Mt. Simon. X occurs because brine has migrated up to the Traverse-Dundee / Silurian-Devonian, where it then interferes with oil and gas production.

The values shown in Figure 4 may be high for a few reasons. Every existing well in this application leaks, and with a very high permeability. Since we only vary this parameter (well permeability) and run one simulation for each of four values, the probabilities derived by RISCS can only be step functions in increments of 25%. More simulations that vary more parameters may reduce the probabilities that enter into the RISCS calculations. Further, the values are not discounted to the present; indeed, these values represent costs in present dollars in the year the leakage or interference events occur. Finally, these results are for continuous injection of CO₂ for 30 years, regardless of whether a leakage event has occurred. If leakage occurs and is detected, regulators will likely require that CO₂ injection be halted and
the leak remedied. The likelihoods of future leaks and interferences are thus reduced. These values for leakage and interference risk over time should be combined with the increasing probability of time that accumulations of leaked fluids will be detected, and interventions remedy the leakages.

4. Conclusions and Discussion

Our approach—the Risk Interference Subsurface CO$_2$ Storage (RISCS) model—facilitates probabilistic assessment of leakage risk from CO$_2$ storage reservoirs. RISCS monetizes leakage risk by combining geophysical fluid flow simulations, 3D geospatial data, and estimates of costs triggered by leakage. RISCS can be used to identify sites where the potential influence of leakage risk on site selection, and allows for a broader inquiry into how stakeholder groups may be differentially impacted across injection sites. Our results highlight how leakage risk is site-specific, the complicated tradeoffs between injection locations, the dependence of leakage risk on the three-dimensional proximity of injection to pathways and potential interferences, and how past and present uses of the subsurface may constrain the viability of locations for future CO$_2$ storage projects.

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