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The Leakage Risk Monetization Model for Geologic CO_2 Storage

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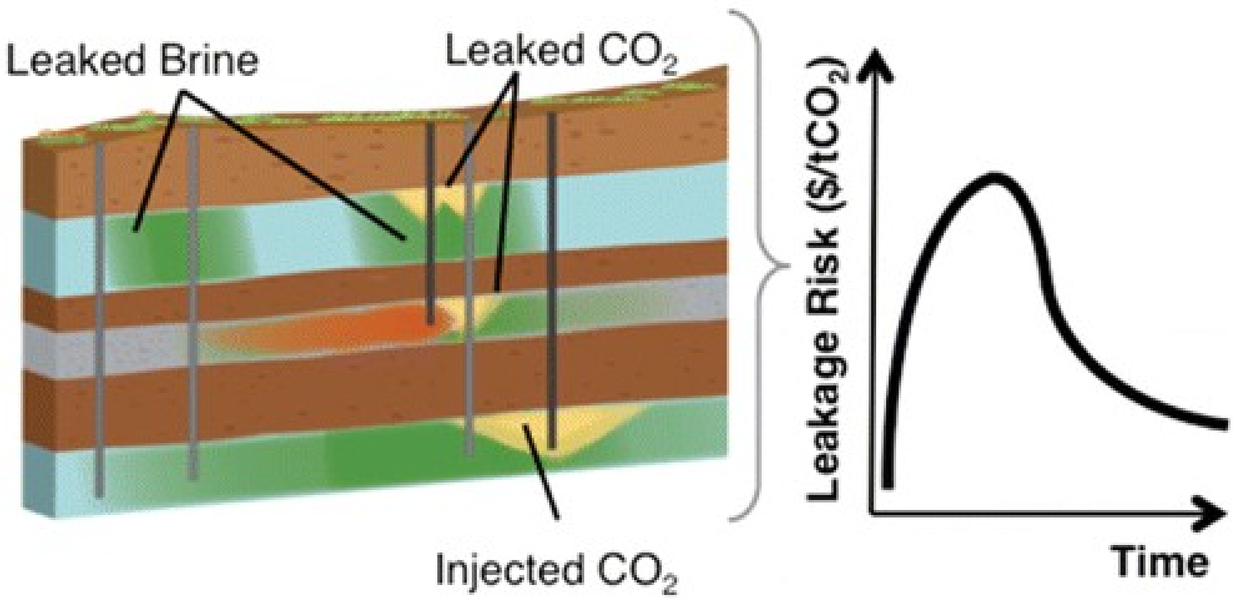
Abstract



We developed the Leakage Risk Monetization Model (LRiMM) which integrates simulation of CO_2leakage from geologic CO_2 storage reservoirs with estimation of monetized leakage risk (MLR). Using geospatial data, LRiMM quantifies financial responsibility if leaked CO_2 or brine interferes with subsurface resources, and estimates the MLR reduction achievable by remediating leaks. We demonstrate LRiMM with simulations of 30 years of injection into the Mt. Simon sandstone at two locations that differ primarily in their proximity to existing wells that could be leakage pathways. The peak MLR for the site nearest the leakage pathways ($7.5/tCO$_2$) was 190x larger than for the farther injection site, illustrating how careful siting would minimize MLR in heavily used sedimentary basins.

Our MLR projections are at least an order of magnitude below overall CO_2 storage costs at well-sited locations, but some stakeholders may incur substantial costs. Reliable methods to detect and remediate leaks could further minimize MLR. For both sites, the risk of CO_2 migrating to potable aquifers or reaching the atmosphere was negligible due to secondary trapping, whereby multiple impervious sedimentary layers trap CO_2 that has leaked through the primary seal of the storage formation.

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Introduction

Meaningful CO_2 emissions reductions achieved through CO_2 capture, utilization, and storage (CCUS) will require the injection of captured CO_2 into sedimentary formations where it is "stored" within the rock matrix for hundreds to thousands of years.(1) Geologic CO_2 storage requires an overlying impervious caprock formation to contain the buoyant CO_2.(2, 3) But the integrity of this caprock may not be perfect and some of the CO_2, or the brine it displaces, may migrate out of the storage formation through leakage pathways (e.g., wells, faults, and fractures) that perforate the caprock.(4, 5) Numerous studies have investigated the physical causes and consequences of this leakage, including: characterizing leakage pathways and caprock integrity;(6-15) simulating horizontal and vertical fluid migration through stratigraphic sequences of sedimentary basins;(16-19) investigating the outcomes of leakage into overlying formations, groundwater, the unsaturated zone, and to the atmosphere;(20-24) developing approaches to verify storage and detect the movement and leakage of CO_2;(25) and remediating leakage by natural or engineered approaches.(26, 27)

Those investigations have yielded essential understanding of geophysical aspects of storage integrity, but leakage events are not all the same in terms of financial implications. As we and others have shown,(28, 29) there are unique costs associated with the possible scenarios including CO_2 leaking but secured by secondary trapping, CO_2 leaking and interfering with valuable resources, CO_2 reaching potable aquifer resources, and CO_2 migrating all the way to the atmosphere. In order to effectively compare storage reservoirs and injection locations, a single monetary metric is needed to interpret leakage predictions. Operators, regulators, policy-makers, and the public require reliable financial risk-based information for site selection, liability, compensation, and expected conformance with regulations.(30) Frameworks for geologic CO_2 storage risk assessment have been developed,(31-33) but they do not monetize the consequences of imperfect storage and leakage remediation.

In this paper we introduce the Leakage Risk Monetization Model (LRiMM), a new approach that integrates and extends two pieces of our prior work. One piece established a method to conduct probabilistic simulations of injection and leakage to produce an expectation of the extent to which leakage could migrate vertically and horizontally through the overlying formations in the hydrostratigraphic sequence.(34) The other piece established the Leakage Impact Valuation (LIV) method to estimate the economic costs of a single leakage event.(28) LRiMM extends that work by estimating geospatial probabilities and extents of leakage and the associated economic costs. The resulting monetized leakage risk (MLR) serves to bound uncertainty about the performance of individual sites, and establishes the basis for modeling of the regional, national, and global deployment potential of CCUS. LRiMM also provides information about potential harms and financial burdens to specific stakeholders, thereby establishing mechanisms to compensate stakeholders who may be negatively affected but unable to directly benefit from the activity.

To demonstrate LRiMM, we compare two case studies of CO_2 injection into a deep saline aquifer in the Michigan sedimentary basin. Specifically, we investigate (a) the magnitude of MLR relative to CO_2 capture costs and with regard to specific stakeholders, (b) the effect of secondary trapping, whereby overlying sedimentary layers trap CO_2 that has leaked through the primary seal of the storage formation, (c) the effects of geospatial proximity of injection wells, leakage pathways, and other subsurface resources, and (d) how the ability to detect and remediate leakage would reduce MLR and stakeholder exposure.

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The Leakage Risk Monetization Model: LRiMM

LRiMM is designed to characterize leakage risk from perspectives ranging from an individual CO_2injection project to regional planning at the scale of sedimentary basins. As shown in Figure 1, LRiMM uses 3D geospatial data on hydrostratigraphic units, other subsurface activities, and potential leakage pathways that intersect the impermeable strata. These data are used in geophysical simulations to produce a probabilistic characterization of the spatial patterns and temporal evolution of leakage. In principle, the LRiMM framework can use any geophysical model that simulates site-specific fluid migration, plume evolution in aquifers, and leakage through any type of pathway. Here, we used a semianalytical model of CO_2 injection, brine displacement, and upconing and leakage through active or abandoned wells.(16, 35) The use of a computationally tractable model enables simulation of multiple injection and leakage scenarios, in which parameters with critical uncertainties (storage reservoir permeability κ_{aq}, storage reservoir porosity ϕ_{aq}, pathway leakage permeability κ_{leak}) are treated probabilistically. As implemented for this work, a 3D recording grid was constructed throughout the domain, which was used to track for each model condition at each time *t* (a) the fraction of the thickness of an aquifer that contains CO_2 ($0 \leq h_{CO_2} \leq 1$), and (b) the increase in brine pressure ($P_{i,t}$). The resulting probabilities of CO_2 or brine leakage were determined by calculating the fraction of simulations in which CO_2 is present ($p_{CO_2,t}$), and in which there is an increase in brine pressure ($p_{P_{i,t}}$), respectively. These probabilities establish the likelihood that CO_2 will be present or an increase in brine pressure will occur at a recorded location at time *t*. (See the Supporting Information for more details.) Additionally, the total mass of CO_2 accumulated in each aquifer (M_i) was quantified. LRiMM differentiates between primary leakage out of the storage reservoir and secondary leakage through pathways above the storage formation.

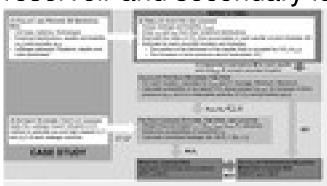

Figure 1. Schematic of the data and processes that are used in LRiMM to monetize leakage risk. The three aspects of siting assessments for CO_2 storage are in white boxes: (1) 3D geospatial data, (2) simulations of injection and leakage, and (3) estimates of economic costs of leakage.

LRIMM classifies leakage into four categories of outcomes, each with unique economic costs. (28) CO_2 or displaced brine could:

(o1) leak out of the storage reservoir but remain secure through secondary trapping,

(o2) interfere with existing subsurface activities,

(o3) migrate into potable groundwater, or

(o4) reach the land surface.

The total risk, or expected cost, of leakage is the sum of the contributions from each outcome (*o*), where each contribution is a function of the probability that CO_2 or non-native brine is present (p_t^o) and the financial impact (I_t^o) for that outcome at a given time (*t*). (See eq 1 in the Supporting Information.) The costs of leakage are determined in *LRiMM* by the LIV method.(28) This method produces plausible low and high cost estimates (I_L, I_H) for each of the four leakage outcomes across 10 stakeholders based on their interests and exposure to leakage outcomes over seven general categories: (1) find and fix a leak, (2) environmental remediation, (3) injection interruption, (4) technical remedies, (5) legal costs, (6) business disruption, and (7) labor burden. (For more details, see the Supporting Information.) Assuming that the estimated costs of leakage grow at the nominal discount rate, I_t^o is thus the constant net present value of these financial impacts at any time *t*. To determine a value of I^o between I_L and I_H, LRiMM uses:

$$I^o(W_{(.)}) = I_L^o + W_{(.)}(I_H^o - I_L^o) \quad (1)$$

where weights are determined from the average fraction of the thickness of an aquifer occupied by CO_2,

$$W_{1,t} = \bar{h}_{CO_2,t} \quad (2)$$

and the average increase in the brine pressure above hydrostatic conditions, P_h,

$$W_{2,t} = \frac{\bar{P}_{i,t}}{P_h} \quad (3)$$

at each recorded location. (See the Supporting Information for more details.)

We defined MLR_t as the expected cost of leakage, R_t, divided by the cumulative amount of CO_2 injected up to that point in time, *t*.

$$\mathrm{MLR}_t = \frac{R_t}{r \cdot t} = \frac{\sum_{o=1}^{4}\{W_{3,t} \cdot [p_{CO_2,t} \cdot I_t^o(W_{1,t}) + (1 - p_{CO_2,t}) \cdot p_{P,t} \cdot I_t^o(W_{2,t})]\}}{r \cdot t} \quad (4)$$

where *r* is the injection rate and the weight $W_{3,t}$ incorporates the potential for multiple leaky wells (*n*) in a grid cell at a recorded location,

$$W_{3,t} = (n)^z \quad (5)$$

In this paper, we use $z = 0.5$ under the assumption that there are cost efficiencies for addressing leaky wells as well density increases. The MLR in eq 4 is determined for each stakeholder and for each aquifer over all grid cells. The results are summed to determine the total MLR.

While the MLR in eq 4 assumes no remediation of leakage, Above Zone Monitoring Intervals are dictated in rules governing CO_2 injection for storage,(36) and leakage that is detected may require remediation. The amount of CO_2 that leaks over time is a priori uncertain, and thus interventions to fix leaks will occur at indeterminate points in the future based on the amount of CO_2 that has leaked and is detected. For a given point in time, LRiMM determines a probability of intervention ($q_t(L)$) that depends on the quantity of CO_2 (*L*) that is detected in aquifers overlying the injection reservoir. This probability distribution could be a function of the monitoring technology, but here we assume perfect detection and remediation technologies so that $q_t(L)$ represents the probability that a detectable amount of CO_2 has accumulated outside of the reservoir and intervention occurs to perfectly remediate that leakage. This probability of intervention is calculated by determining the portion of the simulations where at least *L* has accumulated in the overlying aquifer (see the Supporting Information for more details.) This probability is used to modify R_t, and the MLR arising from unabated leakage to produce the Intervention-Adjusted Risk (IAR) or the Intervention-Adjusted MLR (IAMLR):

$$\mathrm{IAR}_t = R_t \cdot \prod_{\tau=1}^{t} [1 - q_{\tau-1}(L)] \quad (6a)$$

$$\mathrm{IAMLR}_t = \frac{\mathrm{IAR}_t}{r \cdot t} = \mathrm{MLR}_t \cdot \prod_{\tau=1}^{t} [1 - q_{\tau-1}(L)]$$

(6b)where t indexes years since the beginning of injection. CO_2 injection begins at $t = 0$ and thus $q_0(.) = 0$. Eqs 6a and 6b show that IAR and IAMLR are forward-looking projections; if $q_t(L)$ is the probability of perfectly remediating leakage after L is detected outside the reservoir, for leakage risk to exist at time t, L would not have been detected and leakage remediated before t, when $\tau < t$.

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Application to the Michigan Sedimentary Basin

The Mt. Simon Sandstone is a primary candidate for CO_2 storage in the Michigan Sedimentary Basin.(37) Estimates suggest that the Mt. Simon could store 29 $GtCO_2$,(38) which is more than 190× the amount emitted from all sources in the State of Michigan in 2011.(39, 40) The basin contains 57 named sedimentary formations that have been classified into 16 hydrostratigraphic units,(41, 42) and has a long history of subsurface activity (Figure 2). We used an existing 3D geospatial model of the Michigan sedimentary basin that locates the hydrostratigraphic units, wells as leakage pathways, and locations of other subsurface activities(34) to select two case studies for CO_2 injection (Figure 3). These case studies allow us to investigate how proximity to potential leakage pathways and subsurface activities may influence the MLR, and how remediating leakage may reduce MLR and stakeholder exposure to leakage.

Figure 2. Number of subsurface activities in the 16 identified hydrostratigrahic units in the Michigan sedimentary basin. Approximately 60 000 permits for oil and natural gas exploration have been issued since 1927, and 7.2 Mbbl of oil and 120 Bcf of natural gas were produced in 2014, plus an additional 101 Bcf of shale gas was produced in 2013. The basin also contains about one-eighth of U.S. natural gas storage.(40, 43-45) Note. Due to the large number of activities in a few units, the scale of some of the circles has been reduced for visual clarity. These reductions are indicated at the top of the figure.

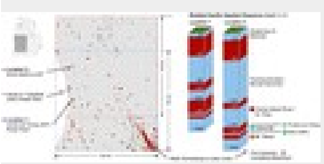

Figure 3. Case study CO_2 injection locations in western Michigan, 9.5 $MtCO_2$/yr is injected into either location 1 (JDY) or location 2 (50 km north of JDY). The map shows the wells that penetrate into the deeper

hydrostratigraphic units using color to indicate the unit in which these wells terminate. The columns on the right show the aquifer (blue)/aquitard (red) sequence for the two injection locations we modeled.

Each case study simulates injection of 9.5 $MtCO_2$/yr over 30 years into the Mt. Simon sandstone. The CO_2 is presumed to be captured from the James De Young (JDY) power plant (0.6 $MtCO_2$/yr) and the J.H. Campbell power plant (8.9 $MtCO_2$/yr), 10 km to the northwest of JDY,(39) assuming 85% capacity factors and 90% capture efficiencies. Location 1 involves injection at the JDY site at a depth of 1600 m, and was chosen because eight UIC Class I disposal wells terminate in the Mt. Simon within 1740 m of this site. These wells are potential leakage pathways, and six of them are active and thus locations where CO_2 or displaced brine could interfere with a subsurface activity. Location 2 is 50 km north of JDY, where the Mt. Simon is deeper, CO_2 is injected at a depth of 1,950 m, and the nearest well that extends into the Mount Simon is ∼20 km to the southeast.

In general, leakage from the Mt. Simon that gets into the overlying Galesville formation may be contained within that formation (i.e., secondary trapping in the Galesville) and not migrate to shallower units (e.g., Trenton-Black River/St. Peter) if the resistance to horizontal flow—a result of the pressure perturbation from injection into stratigraphic nature of sedimentary basins—is less than the resistance to vertical flow; or, if the resistance to vertical flow through permeable leakage pathways is less than the resistance to horizontal flow, leakage may continue upward through the same pathways into shallower formations, or encounter new leakage pathways that do not extend into the storage reservoir (i.e., secondary leakage from the Galesville). Since wells extend from the surface into the subsurface, fluids leaking upward from a deep CO_2 reservoir will likely encounter more wells—and more opportunities for interference with other subsurface activities—if these leaked fluids migrate shallower into the sequence.

The injection and leakage approach we employed has been used in previous studies, where an alternating aquifer-aquitard sequence was constructed from the hydrostratigraphic units.(34, 46) In this work, subsurface activities are located by the use of an active well and the unit in which the well terminates.(34) Five hundred simulations were conducted for each of four well leakage permeabilities that are consistent with empirically measured leakage rates.(14, 47) Each of these 2000 simulations used a unique combination of κ_{leak}, κ_{aq}, and ϕ_{aq}, and the porosity and permeability of the overlying units varied by unit but were held constant across simulations.

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Case Study Results

MLR for Two Injection Sites

[Figure 4](#) shows the MLR for CO_2 injection at location 1 with all wells modeled as leakage pathways. The increase in MLR in the first year is mostly due to primary leakage out of the Mt. Simon through the nearby UIC Class I wells. The MLR for this leakage uses P_i and h_{CO2} in the Galesville, because they indicate the magnitude of the leakage, to weight the LIV estimates for a leakage event between \$2.2 million (I_L^1) and \$86 million (I_H^1) in 2010 U.S. dollars.(28) Direct interference with the waste injection contributes a smaller amount of MLR, and the LIV estimates (I_L^2 = \$1.1 million, I_H^2 = \$4.9 million; \$2010 USD)(28) are weighted by P_i and h_{CO2} within the Mt. Simon, because the interference occurs in that formation.

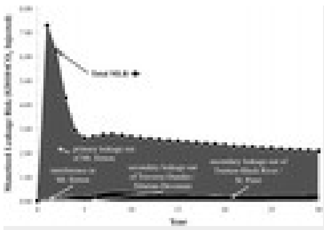

Figure 4. Monetized leakage risk (MLR) profile for CO_2 injection at location 1 (JDY) with all existing wells modeled as leakage pathways. The line with solid circular markers is the total MLR from eq 4. The gray shaded areas indicate the hydrostratigraphic unit where the leakage originated and the crosshatched area indicates where interference with subsurface resources occurs.

Over time, leakage migrates into the Trenton-Black River/St. Peter and further up to the Traverse-Dundee/Silurian-Devonian, some of which occurs through wells that terminate in the Trenton-Black River/St Peter. The MLR for this secondary leakage is small relative to MLR for primary leakage out of the Mt. Simon: ~ \$0.08/tCO_2 in the first year of this secondary leakage (year 3) and reaches a maximum of \$0.34/tCO_2 in year 9. In year 5, leakage may encounter oil and gas production in the Traverse-Dundee/Silurian-Devonian. The LIV estimates (\$2010 USD) for an interference with oil production are \$2.2 million (I_L^2) and \$89 million (I_H^2), and with natural gas production are \$4.4 million (I_L^2) and \$100 million (I_H^2.(28) But the MLR for this interference is at most \$0.001/tCO_2 over the remaining 25 years because secondary trapping reduces the amount of leaked fluids that enter the Traverse-Dundee/Silurian-Devonian and the expected P_i continues to be small relative to P_h. On average, 91% of the total MLR over time is due to primary leakage out of the Mt. Simon through the UIC Class I wells, or interference with the waste disposal by these wells.

[Figure 5](#) shows the MLR for location 2, where the closest well that penetrates into the Mt. Simon is far outside the CO_2 plume. The pressure perturbation in the Mt. Simon drives brine through this and other primary leakage pathways, but P_i in overlying units is small relative to P_h. As a consequence, the MLR at location 2 reaches \$0.04/tCO_2—more than 2 orders of magnitude below the maximum

MLR at location 1, and at most equal to the portion of the MLR at location 1 due to interference with waste disposal. From the standpoint of MLR, location 2 is a better choice than location 1.

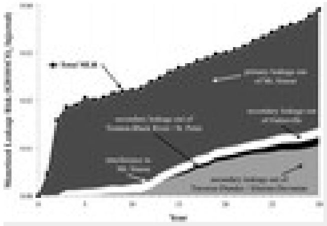

Figure 5. MLR at location 2 with all existing wells modeled as leakage pathways. The line with solid circular markers is the total MLR from eq 4. The gray shaded areas indicate the hydrostratigraphic unit where the leakage originated and the crosshatched area indicates where interference with subsurface resources occurs.

Most of the MLR at location 2 is due to primary leakage out of the Mt. Simon (\$0.02/MtCO_2). In year 3, secondary leakage of displaced brine in the Galesville occurs through other leaky wells, with a MLR between \$0.001/tCO_2 and \$0.002/tCO_2 for the remaining 27 years. Leakage through these wells extends upward into the Traverse-Dundee/Silurian-Devonian in year 7, and in brine that is displaced in the Trenton-Black River/St. Peter also migrates through different leaky wells into the Traverse-Dundee/Silurian-Devonian in year 14. The MLR for this secondary leakage increases over time and reaches \$0.002/tCO_2 by year 30. In the Traverse-Dundee/Silurian-Devonian, the MLR for secondary leakage through many inactive oil and gas wells increases relatively steadily, from \$0.0003/tCO_2 in Year 11 to \$0.011/tCO_2 in Year 30.

These results assume that the real discount rate is zero (nominal discount rate - inflation rate of economic costs from LIV = 0), and thus Figure 4 and Figure 5 show the present value of the MLR. These MLR curves will rotate toward higher estimates of MLR if the real discount rate is negative, and rotate toward lower estimates of MLR if the real discount rate is positive. If the real discount rate is about −1.2%, the MLR at location 1 is roughly constant between year 8 and year 30, at \$2.97/tCO_2–\$3.04/tCO_2. The MLR at location 2 is roughly constant at \$0.016/tCO_2–\$0.018/tCO_2 if the real discount rate is ~3%. The results for the portions of the MLR that are due to primary leakage out of the storage reservoir, secondary leakage out of overlying aquifers, or interference with other activities, are robust to differences in the real discount rate because these differences will equally affect all values at the same point in time. (See the Supporting Information for the results of different real discount rates.)

Figure 4 and Figure 5 show that the distribution of MLR over the subsurface units varies by location. MLR decreases shallower in the sequence at location 1 but increases at location 2. Even though the probability of non-native fluids being present in an aquifer and the degree of alteration of the subsurface environment due to leakage both decrease higher in the sequence,(34) the increase in the number of secondary leakage pathways and cost-incurring activities in shallower aquifers can result in higher portions of MLR being attributable to the shallower aquifers. For the MLR of secondary leakage out of the Traverse-Dundee/Silurian-Devonian at location 2 to increase over time, the number of wells that leak out of the Traverse-Dundee/Silurian-Devonian must increase more than this decrease in pressure.

MLR That Accounts for Intervention

The MLR profiles in Figure 4 and Figure 5 incorporate the assumption that CO_2 injection continues regardless of the occurrence of leakage, and that leakage that occurs will continue unabated. Figure 6 shows the IAMLR for location 1, where only the closest well was modeled as a leakage pathway and the unabated MLR is similar to the case where all wells are modeled as leakage pathways.

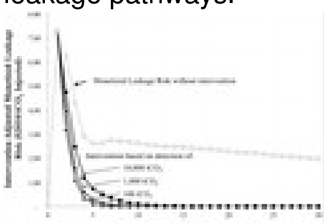

Figure 6. Intervention-Adjusted MLR (IAMLR) at JDY when only one well leaks. The hollow circles are the total leakage risk without intervention to remedy leakage. The triangles, diamonds, and circle markers indicate the IAMLR for the case of successful remediation of the leakage after detection of 100, 1000, and 10 000 tonnes of CO_2 (respectively).

Three IAMLR curves are shown in Figure 6, based on the detection of CO_2 that has leaked into the Galesville aquifer. The possibility of intervention to remediate leakage substantially reduces MLR, even for technologies that can only detect large amounts of leaked CO_2. In fact, within five years of injection and leakage, the IAMLR is less than \$1.00/tCO_2—below the leakage risk attributable to the shallower aquifers—and decreases to less than \$0.10/tCO_2 within five more years. The substantial decrease in MLR occurs in part because location 1 is sited in close proximity to leakage pathways. Cost-incurring impacts of leakage occur early, and the probability of detectable leakage increases over the first few years. For location 2, the MLR and the IAMLR are identical because CO_2 does not leak from the reservoir.

Breakdown by Stakeholder Group

The MLR may be important for stakeholders who could require fees based on the amount of CO_2injected (e.g., Regulators). Other stakeholders with financial exposure to leakage will likely care more about their expected costs, in part because they may have to use financial resources that are not tied to the amount of CO_2 that has been injected.(28) Figure 7 shows the expected costs due to leakage (R_t) at location 1 for a range of stakeholders. The R_t for Storage Operators, who may offset these costs with revenue from storing CO_2, is $71 million in Year 1, which grows to $130 million in Year 5 (assuming that the real discount rate is zero). In contrast, the R_t for Surface Owners, who may not have offsetting revenue, is $1.1 million in Year 1 and doubles to $2.2 million in Year 5 if the real discount rate is zero, but the IAR_t for detecting 1000 tCO_2 is $180,000 in Year 5. Similarly, the R_t for Groundwater Users increases from $59,000 in Year 1 to $100,000 in Year 5 with a zero real discount rate, but the IAR_t is $8,000. In general, nonzero real discount rates will affect the present value of estimated costs from LIV, but conclusions from relative comparisons at the same point in time will not be affected, assuming that individual components of cost estimates change at same rate at a moment in time. (The Supporting Information contains results where the real discount rate was varied.)

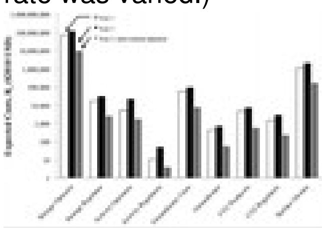

Figure 7. Expected costs of leakage in Year 1 and Year 5 by stakeholder group, for injection at location 1 by when all wells leak. The Year 5 results show the expected costs for the case of continued unabated injection and leakage, and intervention when 1000 tCO_2 is detected for a real discount rate of zero.

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Implications

LRiMM facilitates assessments of the extent to which estimated leakage incurs financial costs, and can (1) compare individual locations; (2) inform mechanisms for the liability and financial responsibility of injection operators; (3) provide information to governments who may assume liability in the postclosure period; and (4) be applied basin-wide to rank the suitability of storage locations and derive and refine resource supply curves. LRiMM also provides regulators and policy-makers with a methodology to develop more efficient and equitable rules for addressing leakage. All told, monetizing leakage risk and addressing the inequity between who is responsible for leakage and who bears the costs may motivate efficient deployment of CCUS.

The case studies presented here demonstrate that CO_2 injection sites should be located with consideration of MLR, which is a product of proximity to potential primary and secondary leakage pathways—through which leakage may occur and incur costs—and other subsurface activities—where interference may incur costs. Our application of LRiMM to potential injection locations within the Michigan sedimentary basin permits several generalizable lessons:

1. MLR will vary over time, but it is likely to be orders of magnitude below the costs of CO_2 storage in well-sited locations.(48)

2. The distribution of MLR within sedimentary units varies by depth. Fewer wells penetrate the deeper aquifers where CO_2 is likely to be injected. The deeper the injection, the lower is the probability and amount of leaked fluids migrating to shallower units both due to fewer leakage pathways and due to secondary trapping as the number of aquifer-aquitard sequences that must be traversed increases.(34)

3. Although MLR can be substantially reduced by relocating injection sites away from leakage pathways and other subsurface activities, even CO_2-brine plumes injected at the most ideal locations within sedimentary basins will likely intersect with potential leakage pathways. The primary determinant of MLR will be the proximity to overlying valuable resources.

4. Our estimated costs of leakage suggest that while Storage Operators will likely have adequate financial resources, leakage may impose costs on other stakeholders who are less likely to have the needed financial resources.

5. The ability to intervene and remediate leakage substantially reduces MLR. Improved methods to reliably detect leaked CO_2 would also reduce the financial exposure to leakage because intervention could occur sooner and avoid future impacts that may be costlier if they grow faster than the discount rate.

The U.S. Department of Energy has set a goal that at most 1% of injected CO_2 can leak from a storage reservoir(34) and the U.S. Environmental Protection Agency defines CO_2 leakage within the Underground Injection Control program Class VI rules as any CO_2 that is detected outside of the injection formation.(36) A truer measure of the reliability of CO_2 storage may not rest in an assessment of how much remains in the storage reservoir, but rather where and to what degree leaked CO_2 incurs impacts and costs, and how these externalities may be unevenly imposed on stakeholders.

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.5b05329.

- Text and figures describing the case studies, a table of nomenclature, a summary table of LIV estimates, fuller description of *LRiMM* methodology, and expanded presentation of results (PDF)

- **PDF**
  - es5b05329_si_001.pdf (4.17 MB)

The Leakage Risk Monetization Model for Geologic CO_2 Storage

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The authors declare no competing financial interest.

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