Improved understanding of geologic CO_2 storage processes requires risk-driven field experiments

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It has long been recognized that the central challenge of carbon dioxide capture and storage (CCS) lies in its vast scale. In order for meaningful greenhouse gas emissions reductions to be effected by CCS, very large amounts of CO_2 will need to be captured, transported, and stored in the deep subsurface. While the quantities of CO_2 that need to be handled in CCS are large, they are of the same order of magnitude as the amount of saline water currently produced along with oil throughout the world and therefore are not unprecedented. It is widely understood that a worldwide CCS infrastructure might look something like the existing oil and gas infrastructure in terms of numbers of pipelines, wells, and processing facilities.

What has not been so well recognized until recently is that challenges of scale extend to subsurface processes. In particular, there is concern about potential large-scale environmental impacts of CCS such as those due to leakage into drinking-water aquifers. Addressing these concerns requires an understanding of subsurface processes that are hard to study in the laboratory. Those processes of particular interest include migration of CO_2 and its monitoring, for example, as it moves upward in unexpected leakage pathways such as permeable faults or decommissioned wells. In addition, there is the potential for hydraulic fracturing and induced seismicity, two issues that are frequently noted in the media recently in relation to natural gas production and geothermal energy extraction. The bridge from natural gas and geothermal energy production – especially as related to fluid injection – to geologic CO_2 storage is very short. The more the research community can understand these processes and develop solutions to address them, the lower will be the environmental risks of CCS.

Clearly, the injection of millions of tonnes of CO_2 per year through a single well or small group of wells into sedimentary systems filled with saline water or brine represents a significant perturbation to the natural system. Responses to this perturbation include pressure increase in the pore fluid that propagates relatively rapidly through the hydrologic system as controlled by permeability and compressibility of the fluid-rock system. The native fluids respond to this pressure increase by flowing away from the injection zone, primarily laterally but also vertically (up and down) as controlled by permeability and pressure. Direct experience with monitoring injection-induced migration of fluid is limited, especially in the public domain, while experience with CO_2 is even rarer. Experiments directed at the detection and monitoring of CO_2 leakage in an existing well or fault, over hundreds of meters or more in extent, would be useful to understand this potential leakage scenario, to develop technologies to quantify the likelihood of it, and to develop approaches for its monitoring, mitigation, and prevention.

Insofar as fluid displacement is limited by permeability, the pressure rise associated with injection must be carefully managed to avoid causing undesirable impacts to the formation. For example, high injection pressures can cause the formation to fracture, creating a new high-permeability flow path. While this flow path may be beneficial to the injection process by increasing effective permeability and associated injectivity, it can also be problematic, in that it bypasses pore space and may lead to inefficient filling of pore space with CO_2. If the fracturing compromises the sealing capacity of the cap rock, it is clearly a concern for long-term CO_2 storage integrity.

Closely related, but not to be confused with the fracturing process, is induced seismicity. Induced seismicity caused by fluid injection occurs as increases in pore-pressure reduce the effective stress in the rock, allowing for shear stresses to manifest themselves through reactivation of existing faults. A related concept is triggered seismicity, in which a critically stressed fault is triggered by a non-tectonic stress change, such as fluid injection. Triggered seismicity would happen eventually without injection, while induced seismicity is unlikely to occur naturally. Faults occur in rocks over a huge range of scales, and most commonly induced seismicity manifests itself as microseismicity, i.e. earthquakes that are too small to be felt at the ground surface. Occasionally, however, these earthquakes are larger, creating impacts at the surface ranging from nuisance to structural damage and safety risk.

Because the pore-pressure rise occurs over a large area, the associated processes of fluid displacement with related geochemical processes, fracturing, and induced seismicity need to be studied over length scales larger than typical bench-scale experiments. Laboratory studies are useful for determining small-scale geomechanical properties, but cannot capture the scale-dependent properties of layered heterogeneous systems. Furthermore, because the response of the system depends on large-scale hydrologic and rock properties, along with the *in situ* stress state (which is difficult to characterize), modeling and simulation can only be used up to a point.

Inevitably, a thorough understanding of the complex processes of fracturing and induced seismicity can only be obtained through field monitoring of experimental injections.

While there are many pilot-scale demonstrations of geologic CO_2 storage going on around the world, along with a few industrial-scale CO_2 storage projects, these projects are aimed at demonstrating the safety and feasibility of CO_2 storage and its monitoring. The kinds of field experiments needed to complement these ongoing demonstrations are those aimed at understanding the circumstances under which things can go wrong. Simply put, the current demonstrations are meant to show how CCS works. What are also needed are tests to answer questions about how a CCS project may fail. Such risk-driven tests would complement risk-assessment efforts that have already been carried out by providing opportunities to validate risk models. In addition to experimenting with high-risk scenarios, these controlled field experiments could help validate monitoring approaches to improve performance assessment and guide development of mitigation strategies.

Attempting to answer questions about how things can go wrong at current demonstration- or industrial-scale sites would be like asking the first buyers of a new model of automobile to use their new cars in crash tests. Certainly a greater understanding of the behavior of the car in collision scenarios would be obtained, but at the cost of learning about the long-term performance of the cars, not to mention the loss of use of the cars to the owners. Note that the monitoring of cars in crash tests looks very different from the monitoring of highway tests, just as the monitoring of a risk-driven field experimental site might look different from the monitoring at existing demonstration and industrial sequestration sites.

What would a field experimental site that could address sequestration risk issues outlined here look like? First, the site should be located conveniently for transportation, to allow researchers and technical support (e.g. drillers, loggers, geophysical contractors) easy access, but it also should be remote enough to avoid conflicts with neighbors, especially with respect to the induced-seismicity experimental objectives. Second, it should be located in proximity to one or more CO_2 sources, because the cost of CO_2 and its transport is a major challenge of CO_2 sequestration field experiments. Third, the geology and structure should be broadly representative of geologic storage targets and contain the features of interest for the testing planned. Finally, the availability of existing site characterization data and infrastructure would offset the need for expensive new infrastructure such as wells and subsurface characterization including seismic interpretations. These site-selection criteria suggest that an oilfield or gas-field location may be the most promising site for experimental facilities.

The geologic storage research community invites comment on this subject, and would of course like to hear about ideas and suggestions for sites and critical experiments. Comments can be emailed directly to me.

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