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Geological storage of captured carbon dioxide as a large-scale carbon mitigation option

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Abstract Carbon capture and storage (CCS), involves capture of CO_2 emissions from power plants and other large stationary sources and subsequent injection of the captured CO_2 into deep geological formations. This is the only technology currently available that allows continued use of fossil fuels while simultaneously reducing emissions of CO_2 to the atmosphere. Although the subsurface injection and subsequent migration of large amounts of CO_2 involve a number of challenges, many decades of research in the earth sciences, focused on fluid movement in porous rocks, provides a strong foundation on which to analyze the system. These analyses indicate that environmental risks associated with large CO_2 injections appear to be manageable.

Plain Language Summary Carbon capture and storage, or CCS, involves capture of CO_2 emissions from power plants and other large stationary sources and subsequent injection of the captured CO2 into deep underground formations. This is the only technology currently available that allows continued use of fossil fuels while simultaneously reducing emissions of CO_2 to the atmosphere. Although the underground injection of large amounts of CO_2 has several remaining challenges, many decades of research in the earth sciences, focused on fluid movement in porous rocks, provides a strong foundation on which to analyze the system. These analyses indicate that environmental risks associated with large CO2 injections appear to be manageable.

Key Points:

- Geological storage of captured CO_2 can play an important role in the transition to a low-carbon energy system
- Many decades of research in the earth sciences have been critical to understand the key processes involved in geological carbon storage
- Environmental risks associated with large-scale implementation appear to be manageable

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1. Introduction

To avoid significant, and potentially catastrophic, global climate change, carbon emissions to the atmosphere must decrease substantially. The scale of the problem is enormous, and multiple technologies will need to be deployed at scale to keep average temperature increases at or near 2°C, which is a target agreed to by more than 190 countries in the recent Paris agreement [*UNFCCC*, 2017].

Only one currently available technology allows continued use of fossil fuels while addressing the carbon problem. That technology is carbon capture and storage (CCS). In this technology, carbon dioxide (CO_2) emissions from large stationary sources are captured before being emitted to the atmosphere. The captured CO_2 is then injected into deep geological formations. Recent studies indicate that CCS needs to play an important role in any cost-effective scenarios to keep average temperature increases below 2° [*IEA*, 2015; *Tollefson*, 2015; *Rockstrom et al.*, 2016, 2017; *Peters et al.*, 2017].

2. The Role of Earth Sciences

Earth sciences play a central role in the analysis of geological carbon storage. The captured carbon dioxide would be injected into deep geological formations, either deep saline aquifers or depleted oil or gas reservoirs, including injection for enhanced oil recovery. When the captured CO_2 is used productively (commercially) in the process of storage, like in the case of enhanced oil recovery, the overall process is usually referred to as carbon capture, utilization, and storage (CCUS). In both cases, the injection formation would be located well below drinking water aquifers, with multiple intervening geological layers serving to protect groundwater resources. The depth of injection, often more than 1 km below the land surface, implies pressures and temperatures above the critical point for CO_2. As such, injection involves supercritical CO_2, which has a density of 250–800 kg/m^3, depending on the depth of injection and the geothermal gradient

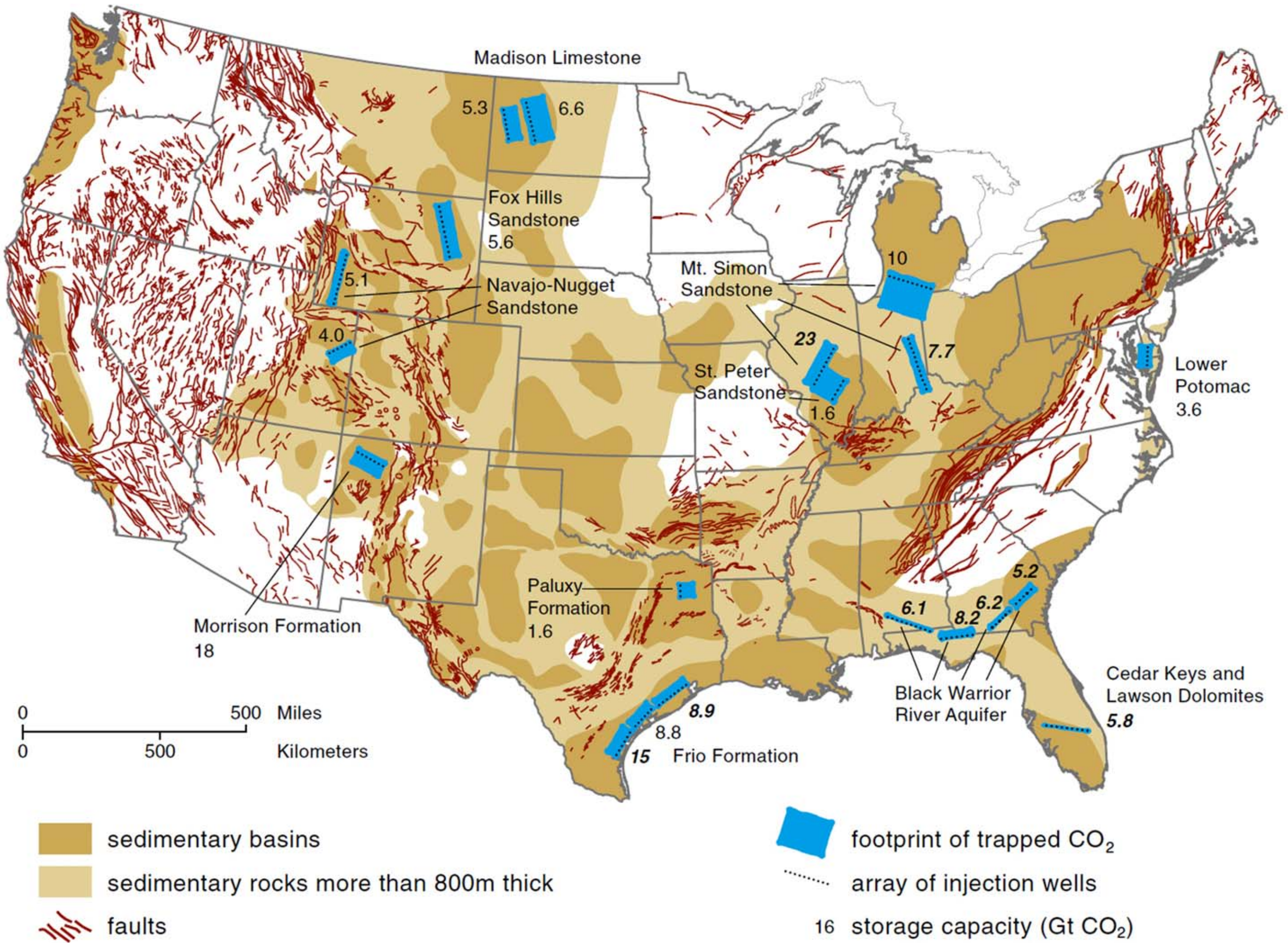

Figure 1. Map showing CO_2 storage capacity estimates for major sedimentary basins in the United States. Eleven different formations were analyzed and the total storage capacity for these formations exceeds 150 Gt CO_2. Figure from *Szulczewski et al*. [2012].

[*Nordbotten et al*., 2005]. While much denser than gaseous CO_2, supercritical CO_2 is still much less dense than the brine in a deep saline aquifer.

Injection of CO_2 increases fluid pressure around the injection wellbore, thereby driving flow away from the wellbore in all directions. Because the supercritical CO_2 is less dense than the resident brine, vertical flow of CO_2 is enhanced by buoyancy. A successful injection thus requires (i) a formation that is sufficiently transmissive (transmissivity = permeability × thickness) and has sufficient pore volume to allow large injection rates over decadal time scales without excessive pressure buildup, and (ii) an overlying caprock formation with sufficiently low permeability to stop upward migration of the buoyant CO_2. Many such formation/caprock sequences have been identified worldwide, and storage capacity appears to be adequate to store emissions over a hundred years or more [*Szulczewski et al*., 2012; *IPCC*, 2005; *North American Carbon Storage Atlas*, 2015]—see Figure 1 for estimated storage capacities in specific deep saline aquifers in the United States. Because CO_2 is only slightly miscible with brine, the system involves two fluid phases, and buoyancy plays an important role [*Nordbotten and Celia*, 2012; *Celia et al*., 2015].

Analysis of CO_2 injection scenarios involves a wide range of mathematical and computational models based on many decades of research on multiphase flow in porous media. This research base includes contributions from the diverse but related fields of hydrogeology and groundwater hydrology, petroleum reservoir engineering, geochemistry, geomechanics, soil science, and contaminant hydrology. These modeling efforts are complemented by data from historical studies of subsurface formations and basins as well as more recent laboratory and field experiments focused specifically on CO_2. These studies involve researchers from academia, government, and industry.

Most modeling efforts have focused on propagation of pressure changes in the injection formation and the associated development and transport of separate-phase CO_2 plumes [*Zhou et al*., 2010; *Birkholzer et al*., 2015; *Bandilla et al*., 2015]. Additional considerations include migration of displaced brine [*Person et al*., 2010; *Celia et al*., 2011], dissolution of CO_2 into the brine and subsequent miscible transport with possible geochemical reactions [*Audigane et al*., 2007; *Johnson et al*., 2004], convective mixing of the dissolved CO_2 [*Riaz et al*., 2006; *Elenius and Gasda*, 2012; *Elenius et al*., 2014; *Emami-Meybodi and Hassanizadeh*, 2015], evaporation of water into the CO_2-rich phase [N*ordbotten and Celia*, 2006; *Pruess*, 2009; *Pruess and Muller*, 2009], and possible geomechanical effects driven by both increases in fluid pressure [*Rutqvist*, 2012; *Zoback and Gorelick*, 2012; *Mazzoldi et al*., 2012; *Zhang et al*., 2013; *Vilarrasa et al*., 2013; *Rutqvist et al*., 2014; *Vilarrasa and Carrera*, 2015], and thermal stresses associated with injection of colder CO_2 [*Preisig and Prévost*, 2011; *Vilarrasa et al*., 2014]. All of these modeling efforts have benefitted greatly from many decades of research in earth sciences and porous media flow.

A unique aspect of geological carbon storage is the large-scale injection of massive amounts of CO_2, which could have unintended adverse environmental consequences including possible leakage of fluids from the injection formation to shallow drinking-water aquifers or to the atmosphere, and possible induced seismicity associated with the elevated fluid pressures [*IPCC*, 2005; *Celia et al*., 2011; *Zoback and Gorelick*, 2012; *Pawar et al*., 2015; *Jones et al*., 2015]. While these risks are potentially important, it appears that proper site selection, site characterization, and possible pressure control through brine extraction, can minimize both of these risks [*Bergmo et al*., 2011; *Birkholzer et al*., 2012; *Court et al*., 2012a; *Juanes et al*., 2012; *Nogues et al*., 2012; *Zhang et al*., 2013; *Tao and Bryant*, 2014; *Vilarrasa and Carrera*, 2015]. The overall result is that the environmental benefits of carbon storage are expected to significantly outweigh the potential environmental risks of large-scale injection, especially given the large benefits associated with keeping average temperature increases below 2°C. However, large-scale injections, involving tens to hundreds of million metric tons of CO_2 per year in the same sedimentary basin, have yet to be demonstrated in the field. And additional research is required to fully address the possible environmental impacts of large-scale injection operations [*Pawar et al*., 2015; *White and Foxall*, 2016] as well as needed technologies for monitoring and verification of large-scale injections [*Jenkins et al*., 2015]. Specific concerns related to potential groundwater contamination include leakage along old wells, leakage along conductive faults, and general uncertainties in caprock structure and integrity over large spatial domains. Also, because geological storage is regulated in the United States by the Environmental Protection Agency (EPA) under the Underground Injection Control (UIC) Program, and the UIC was created under the Safe Drinking Water Act, protection of groundwater is a central consideration in CCS risk assessments. This is one of several ways that water plays an important role in CCS operations [*Court et al*., 2012b].

3. The Current State of CCS

The first industrial-scale injection of captured CO_2 for the purpose of emission avoidance was the Sleipner project off the coast of Norway, operated by the Norwegian oil company Statoil [*Torp and Gale*, 2004]. Statoil produces natural gas from a geological formation deep under the North Sea. The produced gas has a CO_2 content that is too high, so it has to be separated before the gas can be sold. In the early 1990s, Norway implemented a CO_2 emission tax, and when the Sleipner operation came online in 1996, the cost to emit the separated CO_2 was higher than the cost to compress and inject it into a different subsurface formation beneath the North Sea. Since 1996, close to 1 million metric tons of CO_2 has been injected each year (1 Mt CO_2/yr) into the Utsira Formation under the North Sea. Subsequent seismic surveys have shown the location of the separate-phase CO_2 plume and its migration over time [*Arts et al*., 2004; *Chadwick et al*., 2006]. The buoyant CO_2 is remaining in the injection formation and moving up-dip along the bottom of the caprock formation.

In the intervening two decades since the Sleipner project began operation, a number of other industrial-scale projects have been developed, as have several important smaller pilot-scale field experiments. Important industrial-scale projects include the InSalah injection operation in Algeria (injection ended in 2011); the Snohvit injection under the Norwegian North Sea; the Weyburn, Quest, and Boundary Dam projects in

Canada; the Kemper, Petro Nova, and Illinois Industrial projects in the United States; and the Gorgon Project in Australia (see *Global CCS Institute* [2017] for details of each of these). The Sleipner, InSalah, Snohvit, Illinois Industrial, Quest, and Gorgon projects all involve injections into deep saline aquifers, while the other projects use the captured CO_2 for enhanced oil recovery. The deep saline aquifer injections are each at rates of around 1 Mt CO_2/yr, with the Gorgon project, which is just coming online, having the highest planned injection rate of between 3 and 4 Mt CO_2/yr. When combined with other CCS-type activities around the world, the total capacity of CCS projects is approaching 40 Mt CO_2/yr [*Global CCS Institute*, 2017].

The industrial-scale injection projects have capture operations that fall into two broad categories: (i) capture of an already-separated industrial stream of CO_2, like the gas separation associated with the Sleipner Project, and (ii) capture from a combustion-related stream including dilute postcombustion exhaust streams, like those from traditional fossil fuel power plants (with Petro Nova and Boundary Dam as example projects). For the first type, the capture usually adds little to the cost of the overall CCS operation, because the CO_2 has already been separated as part of the underlying industrial process. This leads to low-cost CCS operations, and it is not surprising that most current CCS operations are associated with this kind of capture [*Global CCS Institute*, 2017]. For the second type of capture, the capture costs tend to be relatively high, dominating the overall CCS cost and making the CCS operation relatively expensive. Capture costs from postcombustion dilute streams are estimated to be around 45 U.S. dollars ($45) per ton of CO_2 for new pulverized coal plants and $75/ton CO_2 for natural gas combined cycle plants [*Rubin et al*., 2015]. Similar ranges of costs apply to precombustion capture options [*Rubin et al*., 2015]. Transport to a storage site and subsequent injection adds $10 to $20/ton CO_2 [*Rubin et al*., 2015]. These numbers should probably be seen as representative of so-called nth-of-a-kind (NOAK) systems, based on current technology. First-of-a-kind (FOAK) costs are generally expected to be higher than nth-of-a-kind (NOAK) values. Because the large majority of industrial CO_2 emissions come from combustion-related sources, it is important to develop enough experience to transition from FOAK costs to NOAK costs, while simultaneously benefitting from the development of new lower-cost capture methods.

4. The Scale of the Problem

Current global CO_2 emissions associated with fossil fuels are around 36 billion metric tons (Gt) CO_2/yr [*Le Quere et al*., 2016]. This number has been essentially constant for the last three years, reflecting, in part, the growing importance of wind and solar as well as a shift from coal to gas. While a flattening of emissions with time is an important achievement, the deep decarbonization required to reach the 2° target requires net CO_2 emissions to approach zero by midcentury [*McGlade and Ekins*, 2014; *Tollefson*, 2015; *Rockstrom et al*., 2017]. This will require a massive effort involving all available technologies. For CCS to contribute 10% of the solution requires capture and storage of 3.6 Gt CO_2/yr. Given the current number of 35–40 Mt CO_2/yr for all currently operating CCS operations, this implies an increase by a factor of close to 100 to reach the target of 3.6 Gt CO_2/yr by midcentury. This is a daunting task, made even more challenging by the fact that most global emissions are from dilute, postcombustion streams while most current CCS operations are based on easier-to-capture industrial streams of CO_2 [see *Global CCS Institute*, 2017].

These numbers show that CCS (like every other technology) only makes a significant contribution to solving the carbon problem if its implementation occurs on a very large scale. This requires consideration of large injection operations, in which pressure increases will span across significant parts of major sedimentary basins. An example is the Illinois Basin in the United States, where large power plants and other stationary sources within the basin account for more than 200 Mt CO_2/yr in atmospheric emissions [*Birkholzer and Zhou*, 2009; *Zhou et al*., 2010; *Person et al*., 2010; *Bandilla et al*., 2012]. If these emissions were to be captured and injected within the Illinois Basin, likely into the Mount Simon Formation, a regional approach to CO_2 collection and injection would probably be required [*Zhou et al*., 2010; *Huang et al*., 2014]. This includes development of regional pipeline systems and a coordinated effort to manage multiple injection sites. Clearly coordinated regional planning needs to be developed, and reliable subsurface modeling tools must be able to accommodate domains with areal extent of order one million square kilometers.

5. The Future of CCS

Carbon capture and storage have developed steadily over the last few decades, but the rate of growth of large-scale injection operations has been modest at best [*Reiner*, 2016]. Furthermore, the number of future projects in the planning stage is noticeably smaller than the current number of operating projects [*Global CCS Institute*, 2017]. This lack of acceleration in CCS implementation is due to a combination of (i) the high cost of combustion-related capture, especially in FOAK projects; (ii) concerns about potential environmental risks associated with subsurface injections; and (iii) the overall lack of a price on carbon emissions. Strategies to address each of these need to continue to be pursued. As noted earlier, environmentally safe large-scale injections appear to be feasible, although expanded research and well-planned large-scale injections are needed. Lower-cost capture technologies and carbon pricing are especially important. Reduction of capture costs is a technology challenge while carbon pricing is a political challenge. The need for a carbon price is obvious, because it allows different low-carbon technologies, including CCS, to compete in a properly constructed market, where the cost of environmental degradation associated with CO_2 emissions is internalized to individual emitters.

In terms of subsurface injection, opportunities for large-scale injection operations involving low-cost capture should be sought. As an example, if the planned large-scale synthetic natural gas (SNG) operations in northwest China were to be fully implemented, several hundred million tons of CO_2 would be emitted annually [*Yang and Jackson*, 2013; *Huang*, 2016]. Capture and injection of the CO_2 into available and suitable deep geological formation would be a natural complement to the SNG activities [*Huang*, 2016]. Development of such a project offers the opportunity for meaningful international cooperation around a common objective, and would provide important scientific learning about the impacts of large-scale injections that can be integrated into a practical engineered solution.

Another potential area for large-scale CCS implementation is in the context of dispatchable energy to deal with intermittency of renewables such as wind and solar. Integration of CCS could be part of a more creative set of strategies involving broader approaches to subsurface energy storage and management [*Bourcier et al*., 2011; *Buscheck et al*., 2012, 2013, 2014; *Oldenburg and Pan*, 2013]. Furthermore, future negative emissions scenarios often include CCS as an essential component [*Tollefson*, 2015; *Rockstrom et al*., 2017]. This includes so-called bioenergy with CCS, or BECCS, where biofuels provide the energy source and emissions are captured and sequestered, thereby leading to negative overall emissions [*Kemper*, 2015].

Finally, it is worth noting that in an economic and political climate where fossil fuel use and environmental concerns are often seen as mutually exclusive, CCS might serve as the bridge where fossil fuel supporters and environmentalists can find common ground. CCS is the only available technology that allows continued use of fossil fuels while simultaneously addressing the carbon problem. Its potential to provide a platform for both regional and international cooperation, to bridge the usually divergent groups that either support or oppose fossil fuels, and to play an important role in large-scale penetration of renewables through solutions to the intermittency problem, make CCS a technology that is important to future energy landscapes. Both basic and applied research programs, integrated into large-scale projects with a focus on creative ways to accelerate its use, can lead to new implementation strategies and evolving paradigms that can contribute significantly to our low-carbon energy future. Such a broad approach can place CCS as an important geoscience contribution to the grand challenge of solving the carbon and climate problem over the next several decades.

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