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Mission Innovation task force on enabling Gigatonne-scale CO_2 storage

Phil Ringrose[1]* and Curt Oldenburg[1,2] report on findings of the Mission Innovation task force on CO_2 Storage Injectivity and Capacity – part of the Carbon Capture Innovation Challenge and the newly released report, Accelerating Breakthrough Innovation in Carbon Capture, Utilization, and Storage.

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Introduction

A group of scientists from six countries (France, Netherlands, Norway, Saudi Arabia, UK and the US) met over three days in September 2017 in Houston, Texas, to brainstorm and debate the most promising research directions needed to make breakthroughs in the areas of injectivity and capacity that currently pose challenges to carrying out large-scale (gigatonnes CO_2 per year) geologic carbon sequestration. Several CO_2 storage projects around the world have demonstrated the feasibility of injecting and storing CO_2 at the mega-tonne per year scale. These include the long-running Sleipner project (Norway) which started in 1996 and which has stored ~17 Mt of CO_2 to date, and the Illinois Basin Decatur Project (USA) which has stored approximately 1 Mt of CO_2. New projects have started over the last few years, including the QUEST project in Canada, the Gorgon project in Australia, and the Industrial Carbon Capture and Storage (ICCS) project at Decatur, Illinois, which will inject 1 Mt CO_2/yr. These projects along with a wealth of injection experience from the oil and gas industry over decades, supported by an extensive literature of theory and modelling analyses, provide confidence in the subsurface storage concept intrinsic to CCUS.

The challenge ahead is to ramp up CCUS technology to be able to safely store CO_2 at the gigatonne (Gt) per year scale to meet global CO_2 emissions reductions targets. Although sufficient capacity exists in theory to store CO_2 at the Gt/year scale in the continental and offshore sedimentary basins of North America, Europe, and worldwide, there are many technical challenges that need to be addressed. First, more accurate estimates of storage capacity are needed over large areas (~10^3– 10^4 km^2) that have been targeted for storage, with associated challenges for site characterization, monitoring and storage verification. Second, whereas the few current projects are isolated in the given storage reservoirs and often within entire sedimentary basins, injections at the Gt/year scale must involve multiple large-scale projects potentially within tens of kilometres of one another and accessing similar stratigraphic intervals and probably similar reservoir units. To achieve this degree of scale-up, a better understanding of the permissible pressure increase in these large regions is needed. Pressurization from injection projects is known to extend from 10s to 100s of km from the injection wells, and interference among neighbouring projects is inevitable. Thus, there is the need for detailed understanding of the tolerance for pressure rise and potentially the need for pressure management. Furthermore, large-scale projects will require smart methods for controlling and optimizing CO_2 injection, which will involve developing better understanding of the links between small (e.g., sub-pore and pore scale) and large-scale physical processes in the reservoir.

The key technical issues, questions, and areas in need of better understanding include:

- CO_2 migration and trapping processes;
- Understanding when and how caprocks fail;
- Physics- and chemistry-based understanding of CO_2 all scales in the reservoir and storage complex;
- Impact of flow processes on storage at multiple scales within heterogeneous rock media.

In addition to laboratory and field studies, there are many challenges that will require developments in the theory, modelling, and simulation of CO_2 storage processes. The research challenges identified by the group on Storage Injectivity and Capacity aim to exploit recent advances in the understanding of flow processes and in the use of high-performance computing, using large data sets to improve the forecasting of CO_2 migration and trapping processes, the nature of pressurization and dynamic pressure limits, reservoir fracturing and dynamic geomechanical behaviour of rock units.

After brainstorming the issues, the Expert Panel developed three ‘Priority Research Directions’ (PRDs) considered to be essential to the future ramp-up of CCUS to the Gt scale:

- Advancing multi-physics and multi-scale fluid flow to achieve Gt/yr capacity;
- Dynamic pressure limits for Gigatonne-scale CO_2 injection;
- Optimal injection of CO_2 by control of the near-well environment.

These global research propositions are outlined in the report (Mission Innovation, 2017). Here we summarize the research ambitions involved. The expert group focused primarily on storage in saline aquifers and depleted oil and gas fields, as they are expected to have the largest potential for Gt-scale storage, although the concepts will be relevant to all storage options (including CO_2 EOR).

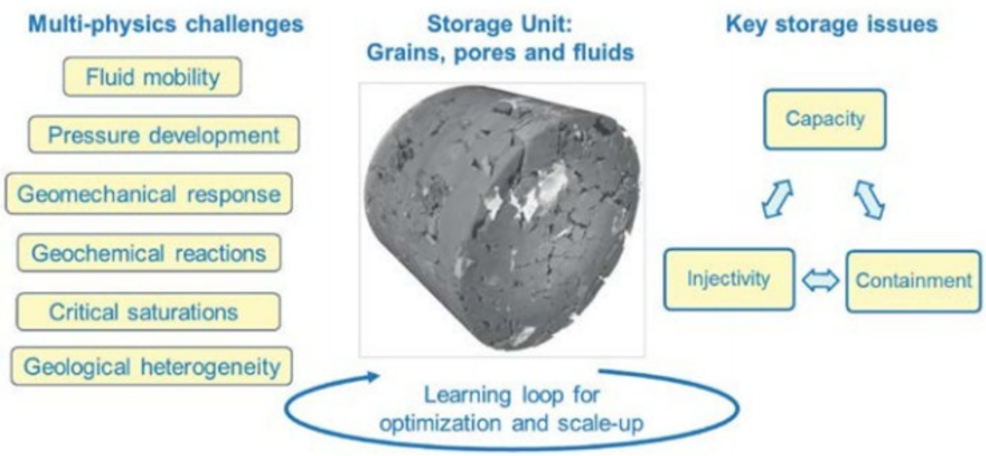

Figure 1 Overview of CO_2 storage challenges (Core image courtesy of Sam Krevor, Imperial College London; Lai et al., 2015).

A key part of the learning process for globally significant scale-up of CO_2 storage has been the insights gained from early mover projects. This experience has been summarized in various monographs [e.g., Chadwick et al., 2008; Hitchon, 2012] and review papers [e.g., Jenkins et al., 2015; Pawar et al., 2015].

Some key achievements in the development of CO_2 include: storage include:

How seismic monitoring can be used to monitor saturation and pressure changes associated with the growth of the CO_2 plume;

- How downhole pressure monitoring can be used to understand the pressure distribution and evolution at storage sites;
- Understanding the rock mechanical response to injection;
- Insights into the complexity of storage reservoirs and the impact of heterogeneity on CO_2 flow paths;
- Development of optimal monitoring and risk management procedures.

These early-mover CO_2 storage projects and the associated research studies demonstrate both the technical viability of CO_2 storage and its challenges, while also pointing to the key technologies involved in project execution. This gives us an excellent basis for the research directions identified in this report, focused on the theme of significant scale-up via improved insights from multi-physics analysis of CO_2 storage (Figure 1).

Challenge 1: Advancing multi-physics and multiscale fluid flow

The physics of injection of CO_2 into a subsurface brine-filled aquifer is part of a class of two-phase flow problems. The CO_2 - brine fluid pair is usually immiscible, and injection of CO_2 mainly follows a drainage process with an unstable mobility ratio. However, as CO_2 migrates in the rock formation, both drainage and imbibition flow cycles may be followed; and a set of geochemical reactions among CO_2, brine, and mineral surfaces will occur. It can be shown analytically that CO_2 in the subsurface typically is distributed with a ‘curved inverted-cone geometry’ (Figure 2). The detailed shape of the CO_2 plume, and therefore the efficiency of the process, is strongly controlled by the fluid mobility, the viscous/gravity ratio, and the geological architecture.

The flow physics is the ultimate control on the key question of storage capacity. For a viscous-dominated case, around 25% of the storage volume could in theory be used (in the absence of pressure constraints). However, the effects of fluid buoyancy (gravity forces) reduces the actual efficiency to a general range of 1-6%. Time-lapse seismic imaging data at the Sleipner CO_2 injection project (Figure 3) allows imaging of the spatial distribution of the CO_2 plume. Using these data, Eiken et al. (2011) estimate the fraction of the pore space used at the Sleipner site to be around 5%. The presence of multiple shale layers in the Utsira sandstone formation has caused additional spreading and trapping of CO_2 at the site, to give a storage efficiency that is higher than would have occurred in a homogeneous sandstone. Near-well storage efficiencies are therefore controlled by the interaction of the fluid migration process (flow physics) with the geological architecture (reservoir heterogeneity). Similar interactions between heterogeneities and fluid forces will control how fast and how far CO_2 will migrate when it flows outside of a structural closure. Forecasting this long-term migration is critical to large-scale CO_2 storage deployment to avoid interferences with other subsurface resources and to limit monitoring costs.

In addition to the physical processes controlling CO_2 as a mobile phase, other important processes and trapping mechanisms involved are residual trapping, solubility trapping, and mineral trapping. These CO_2 trapping mechanisms will work over time to increase storage security in the long term. However, there remains considerable uncertainty around quantifying the efficacy of each process for any particular site, and lack of knowledge regarding how to optimize injection strategies to make the best use of the available pore space.

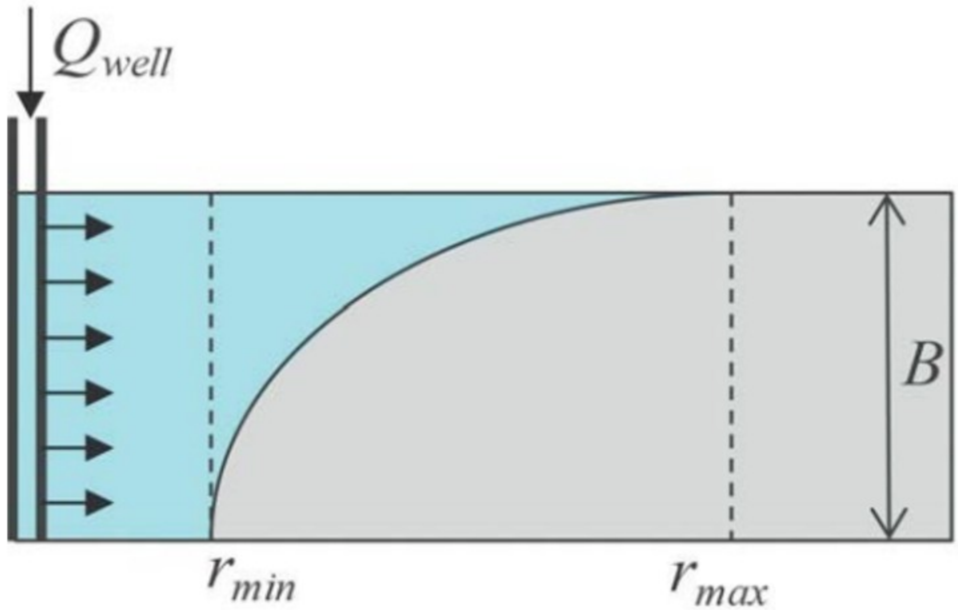

Figure 2 Analytical solution for CO_2 injection (image redrawn from Nordbotten and Celia, 2006).

This leads us to the essential motivation for PRD 1: Advancing multi-physics and multi-scale fluid flow to achieve Gt/ year capacity. The question is how can we better quantify and optimize CO_2 storage efficiency around the injectors?

More specific goals of this research objective are to:

- Evaluate the contributions of different physical processes in controlling near-well CO_2 storage efficiency;
- Consider these multiple physical processes across the multiple scales that control the fluid dynamical processes;
- Research ways in which knowledge of fluid dynamical processes can be used to optimize storage at a given site based on detailed multiscale geological architecture.

Challenge 2: Better understanding of dynamic pressure limits

Alongside the issues of fluid mobility and CO_2 trapping processes involved in storage is the coupled problem of pressure and geomechanics. As CO_2 is injected into the subsurface, some degree of pressure elevation over the background pressure will occur. This pressurization effect has been modelled by analysing end-member geological boundary conditions, which Zhou et al. (2008) summarize in terms of three main systems (Figure 4a). An open storage system has a very large connected aquifer around the storage site, meaning that only limited pressure buildup occurs. In contrast, a closed system (such as a storage site bounded by sealing faults) will have very strong pressure constraints leading to very limited storage capacity. Semi-closed systems represent a fairly common hybrid case in which various partial permeability barriers are found around a storage unit, potentially limiting storage capacity but allowing some pressure dissipation to occur. Note that brine displacement into neighbouring formations will lead to pressure increases in these formations, which may also affect (decrease) their capacity to store CO_2. Real 3D geometries of geologic storage systems are complex and more likely to fall into the semi-open or semi-closed categories (Figure 4b) requiring advanced site characterization and modelling studies.

At the basin scale, all formations are in contact with other formations or hydrogeological units, which can be partly open toward the surface or seabed outcrop. Ensuring successful containment of stored CO_2 thus requires assessment of complex geological systems (the storage complex). Whatever the degree of hydrological communication between rock units, significant pressure rises are expected in the injection area for Gt-scale storage. These must be understood and managed.

Various approaches have been proposed for managing or limiting pressure build-up in CO_2 storage projects; and with scale-up to the Gt/year scale. These pressure management solutions will become critical. Pressure management for CO_2 storage includes the following options:

- Improved understanding of the detailed nature of the geomechanical limits that control the maximum allowable injection pressure
- Optimal use of pressure depletion from gas field production to improve subsequent storage project capacity
- Regional analysis of pressure build-up related to multiple CO_2 injection projects
- Brine production to compensate for CO_2 injection
- Use of novel well solutions to distribute pressure associated with injection

The need to understand and control the pressure and geomechanical responses to CO_2 injection gives the essential motivation for PRD 2: Dynamic pressure limits for Gt-scale CO_2 injection. The overarching question is ‘What are the allowable pressure limits for CO_2 injection projects?’

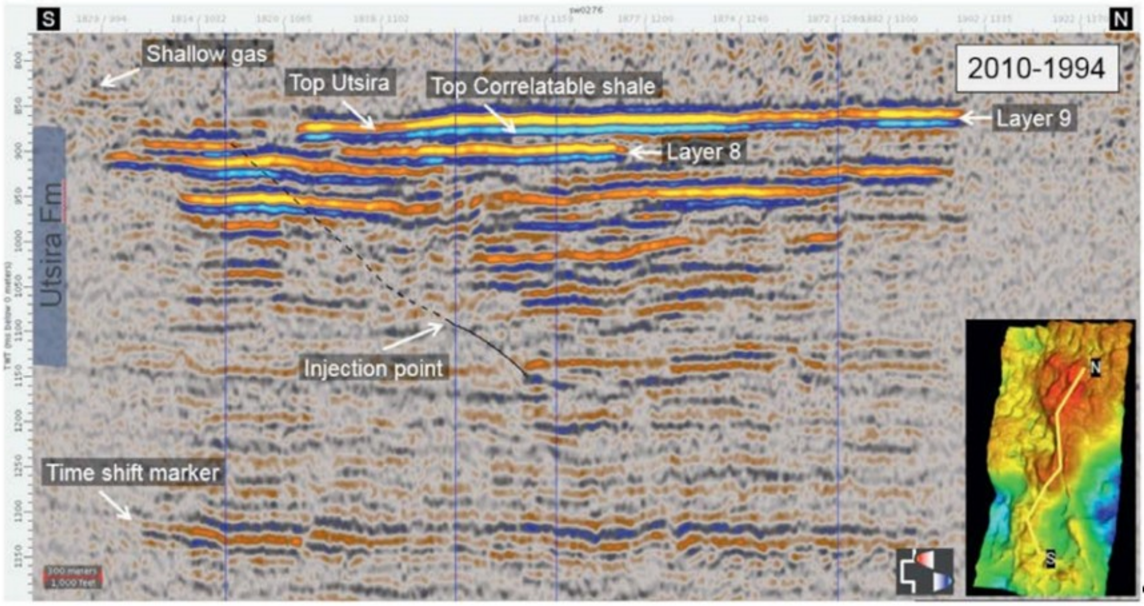

Figure 3 Sleipner time-lapse seismic data, showing amplitude difference between 2010 and 1994 surveys. Bright amplitudes reveal the presence of CO_2 complicated by the effects of time shifts and thin layer effects (Furre et al., 2015; image courtesy of Anne-Kari Furre, Equinor ASA)

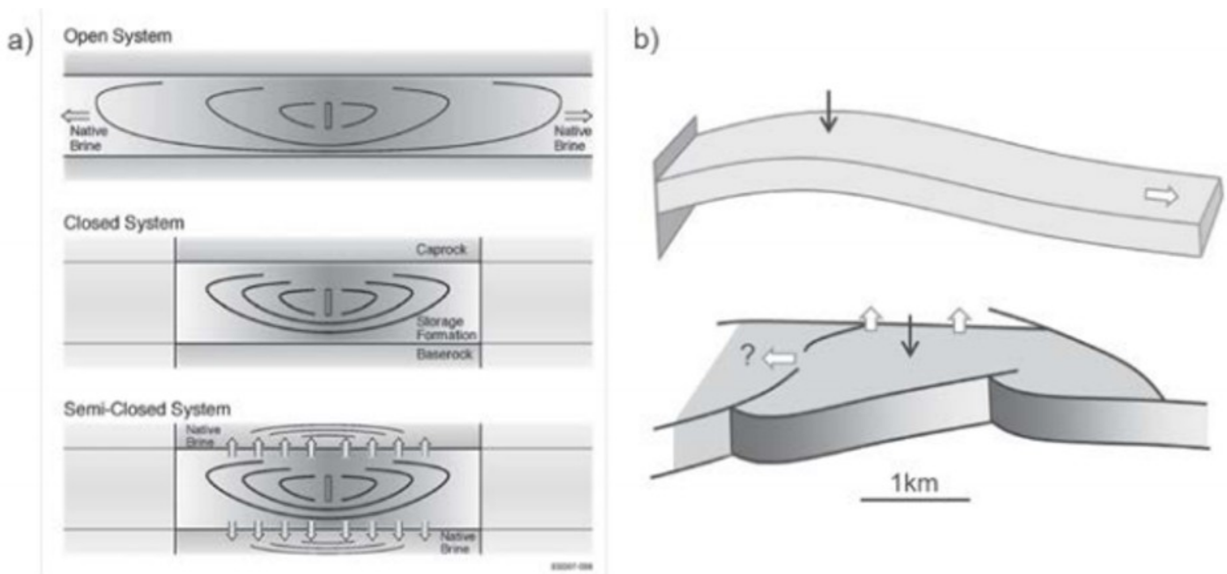

Figure 4 (a) Open, closed, or semi-closed systems (image from Zhou et al., 2008). (b) Typical 3D geometries of semi-open and semi-closed geologic storage systems.

More specific goals of this research objective are to

- Identify and quantify the hydrologic and geomechanical hazards during pressurization
- Improve quantification of the allowable and acceptable reservoir- and basin-scale pressure rises for dynamic CO_2 injection processes
- Improve the understanding of cap-rock and reservoir hydraulic fracturing or fault-slip mechanisms

Challenge 3: Optimizing injection and controlling the near-well environment

Injectivity requirements for Gt-scale injection at multiple sites provide strong motivation to control injectivity and avoid the need for excessive numbers of expensive injection wells. Various processes, such as solids precipitation and formation damage, can decrease injectivity, whereas near-well fracturing and other treatments can enhance injectivity. Fracturing by coupled thermal and hydraulic means is potentially feasible because thermal fractures probably will not threaten cap-rock integrity but rather will remain close to the injection well. Approaches are needed to avoid formation damage and solids precipitation, which may decrease injectivity in the near-well region depending on the composition of the CO_2 injection stream and the local reservoir geochemistry.

Long experience from the oil and gas industry and existing CO_2 injection projects provide a foundation upon which to build a focused research programme for optimal injectivity. The approaches available are: to improve the understanding of induced fractures (hydraulic and thermal) and other near-well treatments to enhance injectivity drawing on combined laboratory, theoretical, and field research, including utilization of underground laboratories. In this area, it is critical to know whether it is possible to develop CO_2 -specific additives that can help manage injectivity, and whether there are feasible next-generation well technologies that can be used to manage injectivity.

The potential for significant developments in optimizing injection gives us the overall motivation for PRD3: Optimal injection of CO_2 by control of the near-well environment:

- To optimize CO_2 injectivity by understanding fracturing mechanisms, using near-well treatments, and deploying next-generation well technology

Multi-scale physics and HPC

How can we achieve the challenges? There is no simple answer. However, there are clear indications to be found in recent advances in imaging and modelling of porous rock media. For example, synchrotron imaging, focused ion beam, X-ray CT and other imaging techniques have been developed and demonstrated to provide the kinds of imaging needed to improve understanding of CO_2 flow an d reaction processe s i n th e por e spac e (e.g. , Sili n e t al. , 20 11; Kneafse y e t al. , 2013). At th e sam e time , advance d computing capabilitie s mak e i t possibl e t o simulat e flui d flo w (e.g. , non -Darcy Stoke s flow) an d reactio n at micro n scale s usin g >20 0 millio n grid block s (Molin s et al. , 2014 ; Trebotic h et al. , 2014).

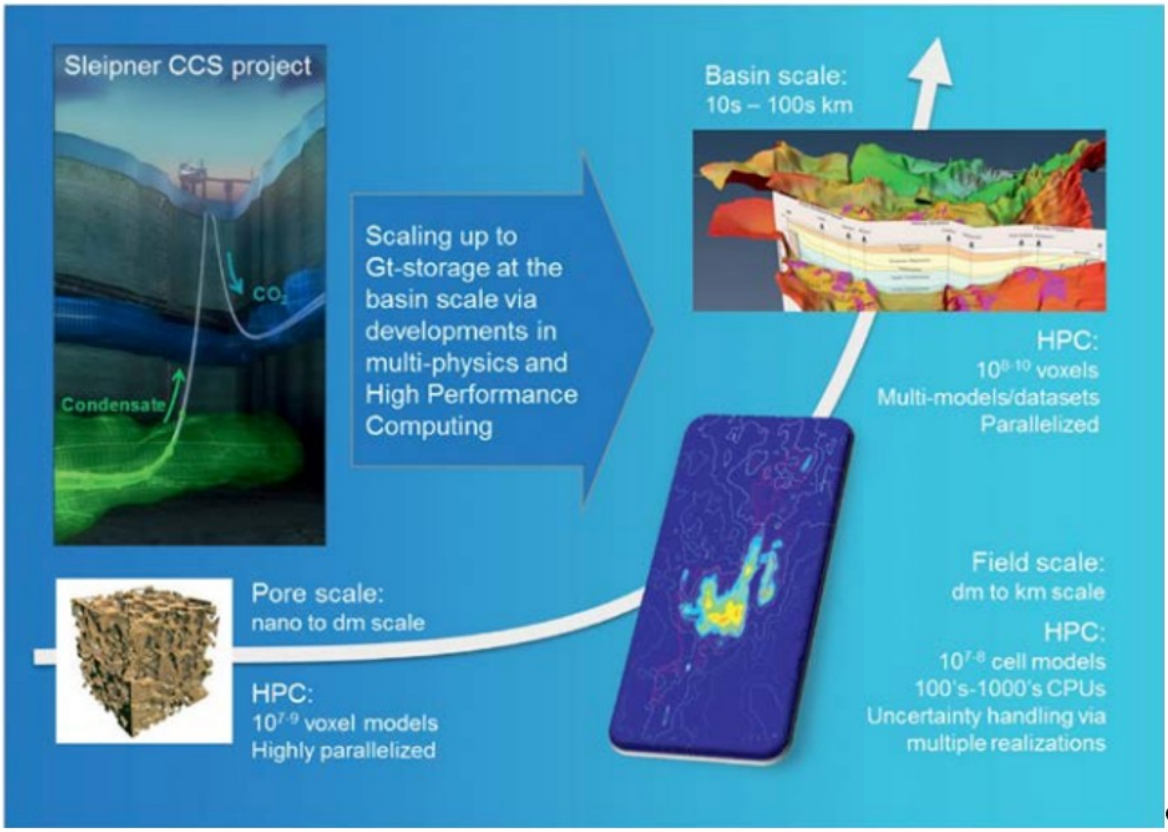

Figure 5 Application of multi-scale physics and HPC to the Gigatonne-scale CO_2 storage challenge (images courtesy of Sam Krevor (Imperial College), Sarah Gasda (University of Bergen) and Equinor ASA)

High-Performance Computing (HPC) simulation capabilities have also been demonstrated for geologic carbon sequestration and other relevant processes on the reservoir scale (e.g., Yamamoto to et al., 2014; Hammond et al., 2014). Not only do the advances in massively parallel computing allow higher resolution of large domains so that heterogeneity and fluid -phase saturations at relevant scales can be modelled, but HPC also allows for more accurate modelling of coupled processes and different physics in different regions. For example, the large pressures generated by Gigatonne -scale per year injection of CO_2 cause changes in the stress field that manifest as geomechanical deformations in composition of the fluid caused by CO_2 injection drive geochemical reactions. In these cases, coupled hydro -mechanical -chemical processes need to be simulated. In addition, flow or other processes in different regions of the domain may be governed by different physics and therefore described by different mathematical models. One example is that the flow in the well needs to be described by the Navier -Stokes equations for viscous flow, while flow in the reservoir can usually be described by Darcy's law. In computing a coupled well -reservoir system, we need to solve the coupled well -reservoir equations (e.g., Pan and Oldenbu rg, 2014). Recent advances in handling and analysing large datasets and in the use of pattern recognition algorithms allow for further possibilities in making advances towards safe and efficient Gigatonne -scale CO_2 injection.

To sum up this ambitious set of challenges, we know that sequestration has to get to the gigatonne (Gt) per year scale to meet global CO_2 emissions reductions targets . We also know how to do 1Mt per year CO_2 injection projects (like Sleipner and Snøhvit in Norwa y, Ques t in Canada and the Illinois Basin Decatur Project in the USA). The question is can we scale up? All agree there are many technical challenges that need to be addressed, and the report (Mission Innovation, 2017) presents these in more detail. The essential requirements for achieving this are partly political (the world's nations must want to do CCS) and partly technical. Concerning the technical challenges, the MI expert group has presented a road-map for scale-up from Mt-scale to Gt-scale. Significant improvements in understanding the multi-scale physics of CO_2 sequestration processes are needed alongside the application of HPC to solve the Gt-storage challenge (Figure 5).

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