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The pressure balancing act in geological storage: sharing the subsurface for the common good

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ABSTRACT

Large-scale geological CO_2 storage (GCS) is essential for achieving net zero targets: its scalability is constrained less by pore volume occupancy than by pressure space—the finite capacity of connected formations to dissipate pressure increases without causing undesirable consequences (such as brine expulsion, induced seismicity, and lower injection rates for a given surface pressure). Current regulatory and commercial frameworks focus on project/site scale containment of CO_2, but as multiple projects start to inject in the same storage formation, the cumulative pressure buildup will limit injectivity long before pore space is filled with CO_2. Here we synthesize the physics of pressure propagation, the geomechanical limits, and interference across multiuser aquifers, and review monitoring and modelling strategies from analytical screening to full field simulations. Drawing on analogues from groundwater management and three regional illustrative examples (Horda Platform, Paris Basin, Captain Fairway), we show that pressure footprints can exceed plume extents by two orders of magnitude and propagate across tens to hundreds of kilometers. We argue that commons-based governance, underpinned by effective monitoring, open data, regional models, and adaptive allocation of pressure budgets, is essential for safe, efficient, and equitable storage. Treating pressure as a shared resource is not optional: it is the foundation for gigatonne scale CO_2 storage and sustainable multiuser use of the subsurface.

Units, glossary

AOI	Area of Interest
CC	Carbon Capture
CCS	Carbon Capture and Storage
DAC	Direct Air Capture
EOR	Enhanced Oil Recovery
GCS	Geological CO_2 storage
MMV	Measurement, Monitoring and Verification
Mtpa	Mega tonnes per annum

1. Introduction

Carbon capture and storage (CCS) is a critical pillar of decarbonization pathways, with deployment targets rising from tens to hundreds of megatonnes of CO_2 per year this decade (IPCC, 2022; European Commission, 2024; International Energy Agency, 2025). This growth is already underway, with hundreds of new projects now in development (GCCSI, 2025). However, growth also brings new challenges. In particular, as projects scale from isolated sites with modest injection volumes to large-scale, multi-hub developments, a systemic constraint becomes

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dominant: reservoir pressure buildup.

The physics are straightforward. Pressure diffusion in high-transmissivity, low-storativity (compressibility) aquifers is fast and far-reaching, whereas CO_2 migration is slow and remains comparatively local. In saline aquifers, injection-related pressure footprints typically extend far beyond the CO_2 plume, potentially extending over tens to hundreds of kilometers and possibly interacting across licenses, assets, and even sectors (Fig. 1; Zhou et al., 2008; Birkholzer et al., 2009; Gasda et al., 2021; Riordan et al., 2025). Where multiple operators inject into the same hydraulic unit, superposed pressure signals can reduce predicted operating windows and may prematurely push injection zones toward regulatory or geomechanical limits (Rutqvist et al., 2012; Zoback and Hennings, 2025). Analogous dynamics are documented in salt-water disposal during unconventional hydrocarbon development, where multi-operator injection has driven regional pressure elevation, sometimes resulting in induced seismicity, changes in ground surface elevation, and/or loss-of-containment incidents (Weingarten et al., 2015; Hennings et al., 2019, 2023).

Despite these realities, most regulatory and commercial practices are still organized around site-scale containment and volumetric accounting of buoyant CO_2, emphasizing trap security and plume migration (Directive 2009/31/EC, 2009; Office of the Federal Register, 2010; Society of Petroleum Engineers, 2025). These considerations are valuable, and they are grounded in well-honed petroleum industry workflows and existing waste disposal regulations, both of which reasonably focus on the injected (or extracted) commodity (Doust, 2010; Shell Exploration and Production, 2013; Bjørlykke, 2015; Lockhart et al., 2018; Roberts et al., 2019). They have been adequate to support the development of CCS over the past five decades, but they are incomplete in ways that are only now becoming consequential.

It is natural to evolve frameworks as CO_2 injection scales up. Historic projects have largely been either CO_2-EOR, where reservoir pressure can be managed by balancing injection and withdrawal, or they have been isolated, small-volume storage projects in relatively giant aquifers that can be fairly approximated as infinite-acting (e.g. Sleipner, Decatur, Quest). Many authors have pointed out that rising reservoir pressure could be a critical limit on injection, but it has largely been a theoretical concern that rarely impacted actual projects (van der Meer, 1992; Obdam et al., 2003; Van der Meer and Yavuz, 2009; Birkholzer and Zhou, 2009; Mathias et al., 2009; Ehlig-Economides and Economides, 2010; Gasda et al., 2017; Anderson and Jahediesfanjani, 2019; Chatelan et al., 2023; Bump and Hovorka, 2024). However, as the scale of injection grows and the number of projects multiplies, the approximation of infinite-acting aquifers breaks down. Without accounting for other injection in the same hydraulic unit, regulators and operators risk over-allocating storage where pressure interference is the binding constraint and under-incentivizing operational levers—such as brine extraction, rate governance, and project sequencing injection—that expand pressure space and/or improve co-existence across users (Thibeau et al., 2014; Buscheck et al., 2016; Energy Technologies Institute, 2018). Perhaps worse, failure to consider the combined effects of all injections into a single hydraulic unit risk exceeding the geomechanical limits of faults, seals, and/or legacy wells that lie beyond the boundaries of individual project areas (e.g., Zoback and Hennings, 2025).

Existing regulations commonly set limits on maximum injection pressure, typically based on the fracture strength of the injection reservoir or primary seal. Many also consider the pressure impact of injection on the reservoir, for example in the US definition of Area of Review, or the Alberta thresholds for induced seismicity. However, they still largely consider projects one at a time, without formal consideration of other injection into the same hydraulic unit. Canny operators may consider the impact of offset injection, if the data is available, but it is not common practice. Even the SPE Storage Resource Management System contains only a passing mention of reservoir pressure, and no mention of offset injection. In short, consideration of reservoir pressure is already common practice, but the assumption of infinite-acting aquifers and isolated projects creates a blind spot.

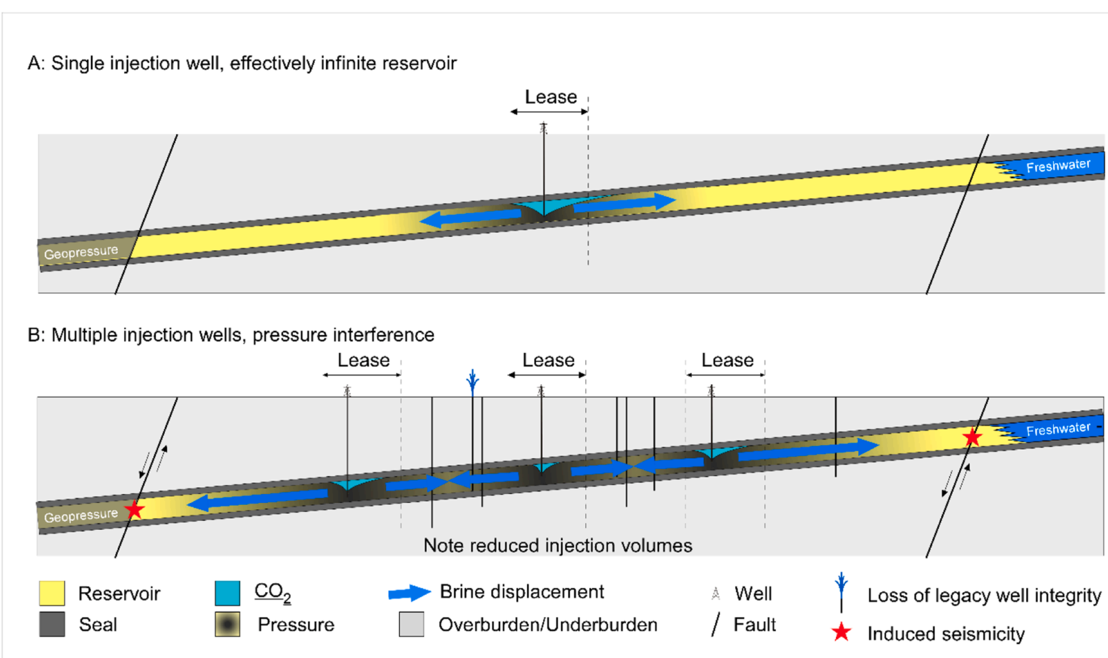


Fig. 1. Schematic diagram illustrating the pressure challenge into a notional reservoir (yellow) with distant lateral boundaries defined by some combination of overpressure, faults, facies changes, and legally protected aquifers. CO_2 injection (light blue) displaces native reservoir brines (dark blue arrows), resulting in pressure buildup (gray shading) that may extend well beyond lease boundaries. With a single injector in a large hydraulic unit (panel A), pressure can dissipate over a large volume, with little consequence. With multiple injectors (panel B), brine displacement may be limited by neighboring injectors, and the reservoir pressure buildup may be higher and more widespread, potentially impacting both planned injection volumes and geomechanical limits, schematically shown here with reduced CO_2 plume sizes, induced seismicity and loss of integrity in one of several legacy wells. Note that the challenges extend across multiple license areas.

Potentially valuable tools and practices already exist in analogous domains. For example, groundwater management treats hydraulic head as a shared, regulated resource, supported by basin-scale models, long-term monitoring networks, reporting mandates, and adaptive allocation rules—tools that might directly translate or be adaptable to CO_2 storage pressure management (McDonald and Harbaugh, 1984, 2003; Department of Water and Environmental Regulation, 2024; Hughes et al., 2019). In parallel, advances in uncertainty-aware digital twins, e.g. regional pressure models, and data assimilation could allow regulators and/or operators to combine monitoring data, possibly from multiple projects, with regional simulations, quantifying uncertainty and updating forecasts as pressure signals emerge (Pettersson et al. 2022; Gahlot et al., 2025).

Fortunately, the aspect of pressure as a major factor is gaining traction within academic, industry and regulatory communities, and a convergence of expert views and collaborative dialogue is quickly evolving. However, there exists no single document that unifies and synthesizes the prevailing knowledge, which creates a barrier to productive engagement with stakeholders and hinders progress towards a coordinated approach to pressure. It is with this backdrop that we have conceived this paper, with the aim of shifting the paradigm on CCS from isolated projects to a new, integrative perspective that includes all injections into a given hydraulic unit.

Specifically, we aim to:

1. highlight emerging challenges in pressure management for large-scale CO_2 storage;
2. initiate conversations on mitigation strategies and regulatory frameworks;
3. and propose innovative operational practices for sustainable, coordinated deployment.

The paper is organized in five sections. First, we synthesize the physics and limits of pressure build-up, interference, and geomechanical integrity at scales relevant to multi-site deployment (Section 2). Second, we set out a regional-modelling workflow—from analytical screening to efficient numerical simulation and hierarchical coupling to sector models—together with monitoring requirements and open-data practices that enable calibration and adaptive management (Section 3). Third, we present illustrative regional studies—Horda Platform (Norway), Paris Basin (France), and the Captain Fairway (UK)—that demonstrate how boundary conditions, legacy depletion, and compartmentalization control pressure footprints and interference distances (Section 4). We then discuss operational methodologies (e.g., brine extraction), and governance mechanisms (e.g., reporting, regional models as license conditions, and cooperative allocation) that align commercial decisions with basin-scale constraints (Sections 5 and 6).

The central message is pragmatic: pressure space is finite and shared. Treating it as such—through regional models, large-scale monitoring (MMV), open reporting, and commons-based governance—will be decisive for unlocking gigatonne-scale CO_2 storage while safeguarding environmental integrity and enabling multi-use of the subsurface (Bump and Hovorka, 2024; Thibeau and Adler, 2023; International Energy Agency, 2025). The monitoring methods are already in use in project scale MMV while hydrology teaches us that policy tools are available; what remains is to implement them consistently at basin scale. We focus here on saline aquifers, as the most widely available and volumetrically largest storage resource, although we acknowledge that locally, pressure-depleted fields may offer an attractive option that avoids or minimizes some of the challenges we highlight (IPCC, 2005; Bentham et al., 2014).

2. Physics and constraints of pressure in GCS

2.1. Why pressure matters in GCS

In the majority of published CO_2 storage atlases, pressure is often treated as a secondary engineering detail in resource assessments. These traditionally emphasize plume containment and volumetric capacity. This assumption is misleading. At basin scale (or in any closed store without fluid removal), pressure—not pore space—sets the practical limit on injectivity and capacity. Injecting CO_2 into a confined system displaces the brine already in the pore spaces and the pressure will rise. At commercial injection rates, formations behave more like closed vessels than infinite sinks, and cumulative pressure from multiple projects can propagate tens to hundreds of kilometers, crossing license boundaries and interacting with other subsurface uses (ref. Fig. 1). These dynamics create a shared-resource problem: uncoordinated injection risks over-pressurization, reduced injectivity, and elevated geomechanical hazards. Treating pressure as a finite, allocable resource is therefore essential for safe, scalable deployment. This principle underpins the governance measures discussed in Section 6.

Regulatory frameworks and resource classification systems, such as the SPE Storage Resources Management System (Society of Petroleum Engineers, 2025), emphasize containment and volumetric estimation of storable CO_2 over millennia. This naturally leads to a focus on buoyant CO_2 volumes accumulating in structural or stratigraphic traps or slowly migrating under the caprock in monoclinal systems until dissolution, mineral, and capillary trapping immobilize the plume. The Endurance structure in the brine-filled Bunter Formation of the Southern North Sea, targeted by the Northern Endurance Partnership in the UK (BP, 2022) is a structural trapping project, while the Basal Cambrian Sandstone used by Quest in Alberta, Canada (Shell, 2011), is a migration trapping project, where CO_2 migrates up-dip and is immobilized through capillary trapping, dissolution, and mineralization. As the first mover projects within their respective basins, they both currently benefit from a large pressure accommodation space.

Fig. 2 is a standard illustration of long-term storage mechanisms, and reinforces the volumetric view of the world. Work by Kearns et al. (2017) highlighted that approaches to pressure differed in different estimation approaches, giving a lower bound to the global storage resource of 8,000Gt and a higher bound (no pressure constraints) of 55, 000Gt. In a recent paper, Gidden et al. (2025) assume that the pressure constraint is the base case, and when the authors include other constraints (geological, economic, technical, cultural, regulatory, and pressure-related), they estimate that only 1460 Gt of CO_2 can be effectively stored. While there has been criticism of some of the constraints in Gidden et al., this evolution of understanding around pressure further underscores the need to incorporate pressure dynamics into resource estimation and project design from the beginning. Indeed, what Fig. 2 omits is that the plume displaces pre-existing fluid: CO_2 emplacement increases the total volume of fluid in the subsurface and displaces existing fluids elsewhere in the connected porous space. This displacement is unavoidable and directly influences pressure buildup, injectivity, and storage security. The next two sections provide the physical and geological context essential for understanding pressure interference in regional saline aquifers.

2.2. Fluid physics and storage efficiency

Injected CO_2 at reservoir conditions is less dense than brine, thus one tonne of CO_2 occupies more volume than one tonne of brine. Fig. 3 illustrates this relationship using typical geothermal and hydrostatic gradients. At ~1 km depth, this translates to 1 t of CO_2 displacing ~1.5 m^3 of brine (Span and Wagner, 1996).

Keeping in mind that the displaced brine induces a pressure front, it is useful to review the basics of the mechanisms of pressure rise and dissipation in open vs closed systems.

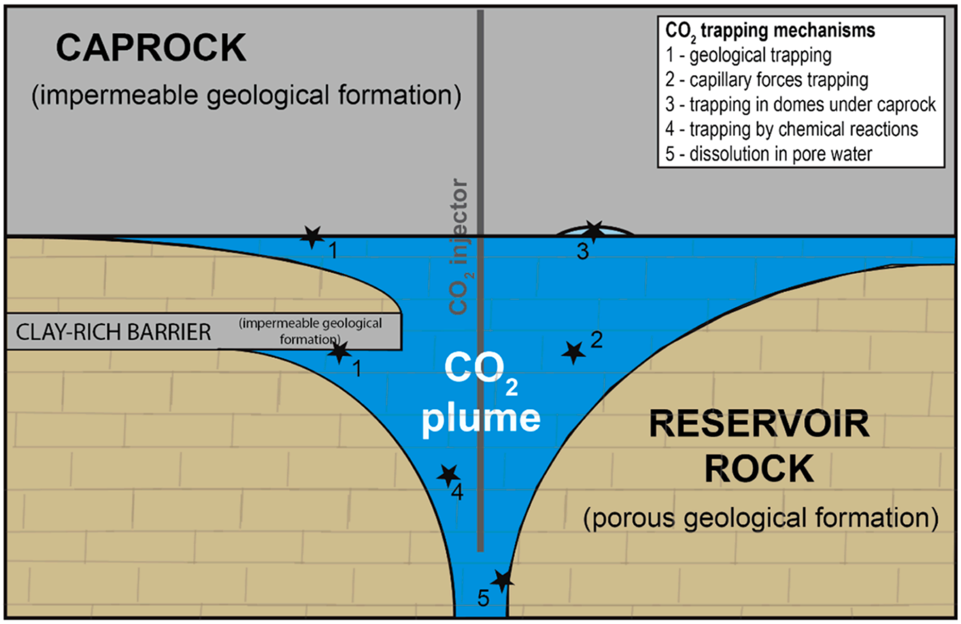


Fig. 2. Schematic illustration of the main CO_2 trapping mechanisms in a porous reservoir.

In a closed system, pressure rise is governed by total compressibility of rock and fluid:

$$\Delta P = \frac{\Delta V}{c_t V_\phi}, \ c_t = c_w + c_r$$

where ΔV is the change in subsurface fluid volume (i.e. it is the volume occupied by the injected CO_2), V_ϕ is the total pore volume, and c_t is total compressibility (the sum of the compressibility of the brine (c_w) and rock (c_r)). Using values from (Zhou et al., 2008) of $c_w \approx 3.5 \times 10^{-4}$ MPa^{-1} and $c_r \approx 4.5 \times 10^{-4}$ MPa^{-1} and an overpressure of 6.0 MPa, yields a closed system storage efficiency is ~0.48 % of connected pore volume.

In open systems, pressure changes are defined by the transient solution to the pressure diffusion equation. This is well documented in well testing literature for a constant rate Q (at reservoir conditions) extending for time t for a cylindrically symmetric system.

$$p = p_i - \frac{Q\mu}{4\pi kh} c_t \left(\frac{\mu\phi c_t}{4k} \frac{r^2}{t} \right)$$

Where E_i is exponential integral, p_i the initial reservoir pressure, μ the viscosity of the pore fluid, k the permeability, h the thickness, r the distance from the injection point (Slotte and Berg, 2017). Q is negative for injection. This equation gives a roughly logarithmic fall off of pressure with distance. It can be shown (Slotte and Berg, 2017) that the pressure is unchanged after a distance of

$$r_p = \sqrt{12Dt}$$

where D is the hydraulic diffusivity and equals $k/\mu\phi c_t$, a term common to petroleum engineering and hydrology. The derivative of this with respect to time gives the rate of hydraulic diffusivity of the pressure front for a cylindrical system.

$$rv_{pd} = \sqrt{\frac{3D}{t} 2Dt},$$

High-permeability, low-storativity (compressibility) formations transmit pressure rapidly, creating footprints far larger than the CO_2 plume. An open boundary does not mean that there is no pressure increase.

2.3. Pressure constraints, poroelasticity, and geomechanical integrity

Pressure cannot rise indefinitely. Exceeding fracture or fault slip thresholds risks caprock integrity and induced seismicity (Rutqvist et al., 2012; Zoback and Hennings, 2025). Allowable overpressure varies with depth and stress regime, often 10 bars near shallow seals versus >100 bars at depth. From a simple tensile fracture perspective, shallow zones often govern the safe operating window for an entire basin. However, there are usually more complex relations that set the geomechanical limits: elevated pore pressure changes the stress in the subsurface which can result in poroelastic effects such as surface uplift or seismic activation of critically stressed faults (see McDermott et al., 2016; Zoback and Hennings, 2025), such as that reported by Goertz-Allmann et al. (2024) at the Quest CCS project in Aberta, Canada. The relationship between pore pressure changes and seismic activity remains complex and not fully understood, as not all pressure increases trigger seismicity and other factors also influence event occurrence.

Beyond hydraulic effects, poroelastic stress transfer amplifies the challenge. Injection-induced pressure changes deform the rock matrix, altering normal and shear stresses on faults and fractures well beyond the pore fluid pressure-change zone. In the context of enhanced geothermal systems, Kivi et al. (2024) demonstrated that accurate modeling of induced seismicity requires consideration of both pressure diffusion and poroelastic stress. Similar findings were reported by Bourne et al. (2014) in the context of gas depletion in the Netherlands, where poroelastic effects extended beyond the immediate pressure-change zone and explained the spatial distribution of induced seismicity.

Increased fluid pressure also alters the balance of hydrostatic forces within the system. Higher injection pressures are required to maintain flow rates, necessitating more powerful pumps and greater energy input. Locally elevated injection pressures may exceed regulatory thresholds and risk inducing fracturing near the wellbore, which is prohibited in some jurisdictions. Moreover, pressure changes can influence the energy efficiency of neighboring injection operations, whether for CO_2 storage or geothermal energy. A further concern is the potential for fluid migration along legacy wellbores from mining, water or hydrocarbon extraction. If these wells are inadequately sealed, elevated pressures can drive fluids upward, potentially reaching the surface or contaminating shallower aquifers, including those used for drinking water. Similar to

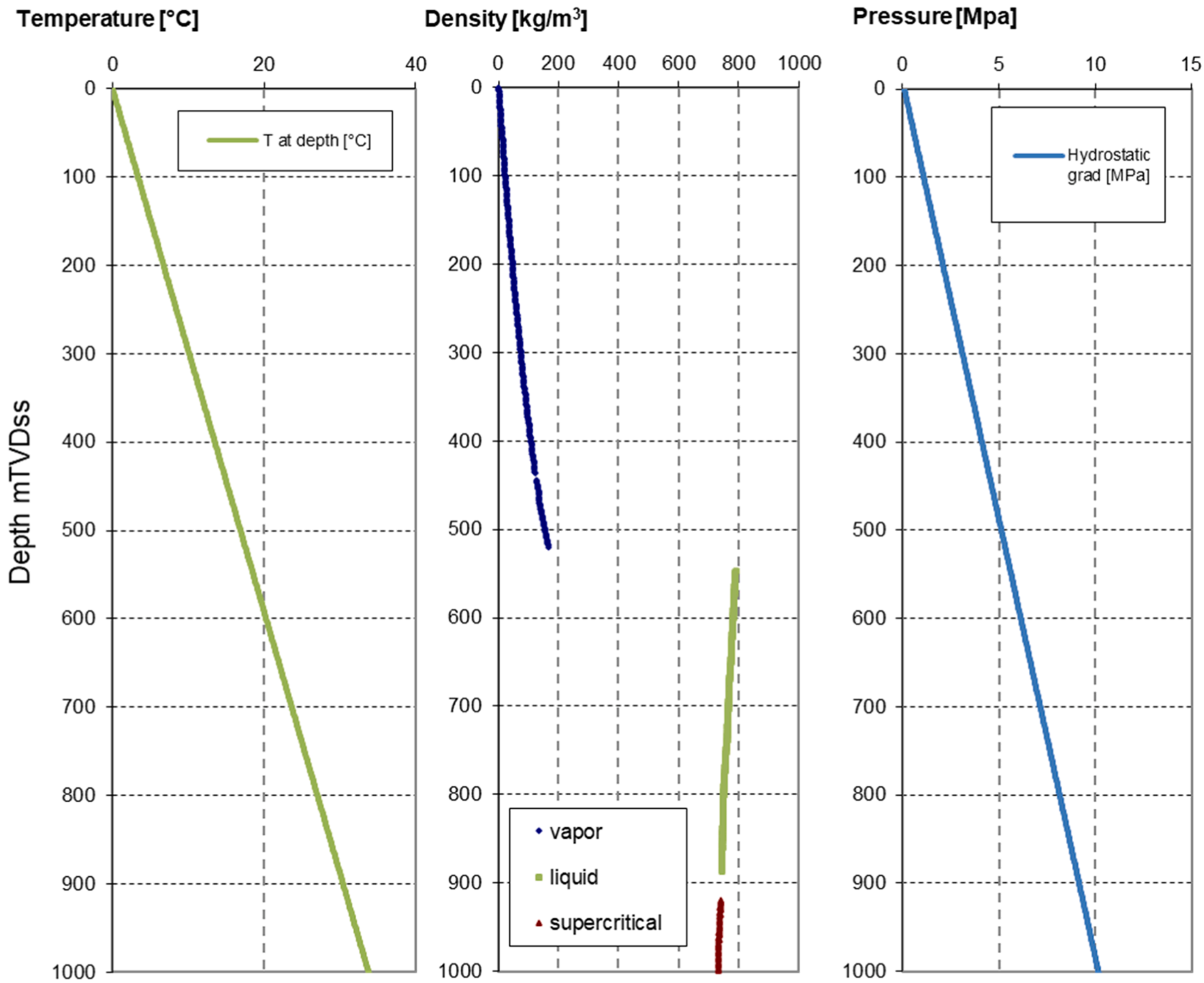


Fig. 3. Pure CO_2 density vs depth, an offshore example, modified from Tucker (2018) (reproduced with permission). CO_2 properties calculated from the NIST Chemistry WebBook (National Institute of Standards and Technology, 2025), based on the Span and Wagner equation of state (Span and Wagner, 1996).

how groundwater extraction alters the water table, CO_2 injection can modify the hydraulic head in connected aquifers (Nicot, 2009).

The combined effect of pressure buildup and poroelastic coupling means that pressure budgets—not volumetric capacity—should define storage allocations. Managing these budgets requires basin-scale models, monitoring networks, and adaptive governance (as will be discussed in Sections 3 and 4), as well as operational levers such as brine extraction (see Section 5 on Water Production) and coordinated licensing (in Section 6 on Regulation and Governance).

3. Regional-Scale pressure modelling for GCS

3.1. Purpose and scope

With pressure now established as a key constraint on regional-scale GCS, this Section focuses on the methodologies used to assess pressure impacts on resource estimation and management. Regional-scale modelling provides the only defensible basis for allocating storage capacity in hydraulically connected systems. Unlike site-scale models, which focus on plume migration and containment, regional models capture cumulative pressure effects across multiple licenses, legacy fields, and other subsurface users (e.g., geothermal, groundwater, hydrocarbons).

The objectives of regional modelling are to:

- Quantify pressure footprints and interference under realistic development scenarios.
- Define safe operating envelopes based on geomechanical limits.
- Support regulatory decisions on licensing, sequencing, and pressure-budget allocation.
- Provide boundary conditions for high-resolution sector models (more in sub-subsection 3.5.3).

These models are typically developed by regulators, geological surveys, or joint-industry consortia in a coordinated fashion. In certain cases, operators may be required to demonstrate non-interference with neighboring assets.

Fig. 4 illustrates a high-level workflow for regional-scale pressure modeling, which typically involves geological modeling and dynamic simulation to predict pressure in a large regional aquifer. While the overall approach is analogous to standard GCS site assessment workflows (in turn originally adapted from oil and gas practices), it must now be further adapted to account for multiple subsurface users (e.g., groundwater, geothermal, oil and gas) and the distinct dynamics of pressure evolution in GCS. In particular, the rapid nature of pressure dissipation over a wide area requires a different modelling mindset compared to storage site assessment or conventional hydrocarbon reservoir simulations. This distinction will be explored in detail in the following subsections.

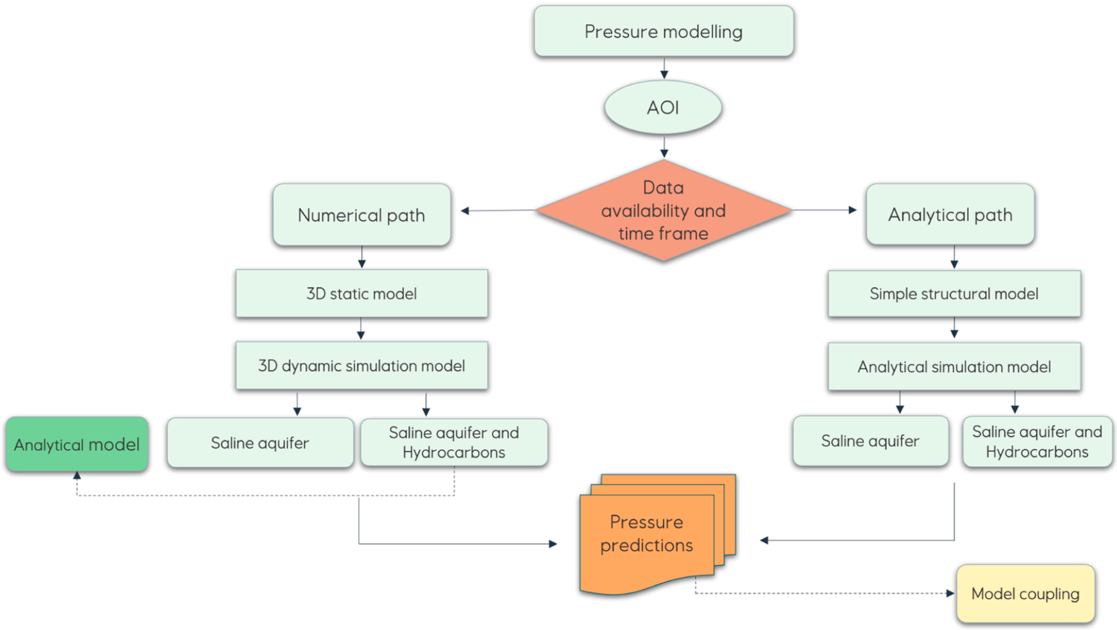


Fig. 4. Hierarchical workflow illustrates two alternative pathways for pressure modelling and prediction, an analytical path and a numerical path (Equinor internal workflow). The less time-demanding analytical path may also be used as a proxy for full numerical simulations and will in many cases be sufficient. The model outcomes for the different paths may then in turn be used for coupling high-resolution sector models to larger regional models if relevant.

3.2. Conceptual framework and area of interest

A regional study starts with a clear definition of the Area of Interest (AOI) for pressure. In this paper, the pressure AOI denotes the lateral and vertical extent over which operational activities are expected to produce a measurable pressure signal during the assessment horizon. It typically exceeds a single project's AOI and is not synonymous with the U.S. Class VI Area of Review for permitting, which is a regulatory construct focused on protecting underground sources of drinking water (U.S. Environmental Protection Agency, 2025).

A practical approach is to begin with the full horizontal and vertical extent of the hydraulically connected aquifer(s) or aquifer system and to iteratively prune the domain once preliminary simulations show where pressure increments diminish below agreed thresholds. Because pressure diffusion is sensitive to connectivity internal to the aquifer, the conceptual model should represent structural and stratigraphic architecture that controls lateral pressure communication, including faults, sand-pinchouts, erosional contacts, and any transmissive or sealing juxtapositions. The regional boundaries at the outer extent of the aquifer should be modeled explicitly, including bounding faults, outcrops or subcrops, to preserve the correct response when the pressure signal reaches the far field.

Vertical communication through fault damage zones, injectites, or eroded shale stringers requires particular attention in otherwise layer-cake settings, since even limited vertical leak-off can strongly moderate overpressure on operational timescales. Initial conditions should represent regional pressure and temperature gradients as well as any production and injection history that have preconditioned the system.

Finally, the conceptual model should incorporate publicly available, or regulator held information on permitted maximum injection rates and planned brine production, since these boundary forcing terms can dominate future pressure trajectories.

3.3. Modelling approaches

Regional pressure problems can be addressed with a spectrum of models. Analytical tools are best suited for early screening, rapid scenario exploration, and sensitivity scoping. Numerical simulators are needed as complexity grows, for example when heterogeneity, boundaries, multiphase effects, or time-dependent external activities must be represented. The most robust programs use analytical models to frame the problem and identify the dominant uncertainties, then move to numerical simulation for calibrated forecasting and decision support (Zhou et al., 2008; Birkholzer et al., 2009).

3.3.1. Analytical modelling

Analytical solutions from hydrology and petroleum engineering give transparent, computationally inexpensive estimates of pressure response to injection and production. Classical radial solutions using superposition can approximate the aggregate effect of multiple wells in homogeneous settings and allow closed boundaries to be represented with reflector sources. Software tools such as EASiTool (e.g. Wang et al., 2025) and CO2Block (de Simone and Krevor, 2021) have been applied to Area of Review and interference questions for other CCS projects under shared formations. Analogous fast estimate calculators exist for CO_2 scenarios that treat the far field as effectively single phase with appropriate compressibility (Wang et al., 2025). These methods are most reliable for establishing orders of magnitude and for mapping which parameters—permeability thickness, storativity, boundary openness, or rate schedules—dominate outcomes. They become insufficient when heterogeneity, complex boundaries, or multiuser time dependence must be represented with fidelity.

Material-balance formulations such as MBAL (Petroleum Experts) approximate the region as a set of zero-dimensional tanks connected by transmissibilities; the approach is especially useful where geology suggests compartmentalization, but detailed 3D models are not yet warranted. In practice, transmissibilities are inferred from structural segmentation, spill-point architecture, facies belts, and legacy pressure history, and can be tuned when adequate pressure data exist (Zahid et al., 2024; Dahlberg, 1995). An example of MBAL tank division of the Horda platform is illustrated in Fig. 5.

In this example, average properties such as temperature, initial pressure, porosity, and water in place are taken from an existing geogrid or, during early screening, estimated from seismic data, exploration wells, and analogues. The AOI, i.e. regional aquifer system, is divided into tanks, and connection nodes between them represent

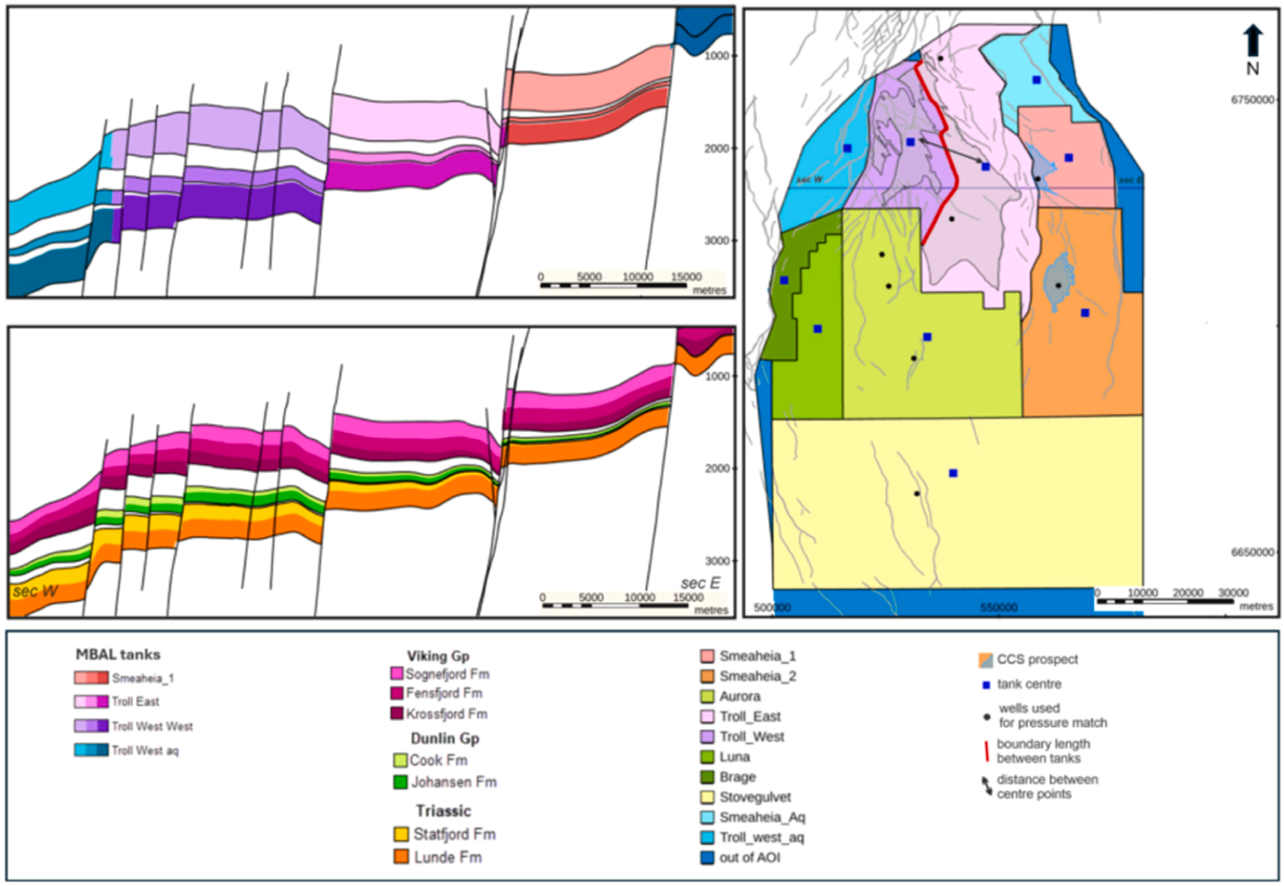


Fig. 5. MBAL tank set-up for the Horda platform based on a combination of license boundaries and major fault segmentation (Zahid et al., 2024).

transmissibility, which reflects geological understanding of lateral connectivity and can be history-matched where pressure data exist. Fluid injection or withdrawal in each tank produces an average pressure response governed by fluid and rock compressibility, while transmissibility values control inter-tank flow and can be refined using design matrices as new data become available. This material-balance approach, implemented in MBAL, has proven effective for predicting and matching historical pressure behavior on the Horda Platform (Zahid et al., 2024).

3.3.2. Numerical modelling and simulations

Numerical models inherit the conceptual geological model and render it on a simulation grid whose design is appropriate for modeling the physics of pressure dissipation. Because pressure communication is predominantly lateral on operational timescales, stratigraphic grids that represent structural topography and preserve pressure communication are preferred. Fine-scale heterogeneity that is critical for plume migration is often less important for pressure dynamics, and careful upscaling to preserve permeability-thickness and lateral connectivity is therefore warranted to maintain tractability. The grid domain should cover the full aquifer extent, and associated boundary conditions should preserve the far-field physical boundaries of the regional system, e.g. outcrops and subcrops, pinch-outs, bounding faults, and pressure boundaries. If a smaller domain is chosen, then care should be taken in correctly incorporating all off-model activity that can impact pressure development (see next section).

For large basins, two-dimensional representations that collapse vertical resolution into a single layer per hydraulic unit can reproduce lateral pressure evolution with high accuracy at a fraction of the computational cost. This technique is commonly used to model geohydrological systems (see Section 3.4) and produces reliable results provided the lateral transmissibility (kH or permeability–thickness) is correctly upscaled from representative 3D descriptions and that vertical leak-off pathways are captured in the effective properties (Landa-Marbán et al., 2025; Tveit et al., 2024).

The treatment of fluid phases must be consistent with the regional question. In many regional settings the far field is overwhelmingly brine saturated, and pressure can be advanced with single-phase formulations. However, it is often advised to retain a coarse multiphase representation where CO_2 volumes are nonnegligible so that the higher compressibility of the CO_2 phase is captured in the regional pressure response. Simulator choice is secondary to model design; widely used tools from both the petroleum and hydrogeology lineages solve the same governing equations and can be configured for CO_2 storage pressure studies, including such as the SLB and CMG suite of commercial simulators (ECLIPSE, INTERSECT, and GEM) along with open-source codes such as OPM Flow (Rasmussen et al., 2021), the TOUGH family codes, and Cirrus and multiphysics platforms (Nazarian and Furre, 2022; Sun, 2015) to cite a few.

3.3.3. Linking regional pressure models with sector/store scale plume models

If the engineering workflow requires a smaller sector model, for example to focus on plume migration or geophysical data integration, then sector boundary conditions require particular care. Static boundaries or analytical or numerical aquifer terms that ignore time-dependent activity outside the model window can produce misleading sector-scale results. Because pressure interference is inherently dynamic, sector boundaries should inherit time-varying pressures from a regional model that resolves external activity.

Where significant off-model activity is expected, a practical workflow can be deployed that is hierarchical in nature, i.e. a regional model simulation on a coarse grid is combined with fine scale simulations on the sector model with transfer of boundary conditions both in space and time (Tveit et al., 2025). Such an approach is simulator-agnostic, requires no calibration of pseudo-wells, and allows the regional and sector models to live on different grids or even platforms. It has been demonstrated on Norwegian North Sea cases and avoids the well-known pitfalls of pore-volume multipliers and static aquifer terms that cannot represent time dependence or mixed compressibilities consistently (Tveit et al., 2024; 2025). Specific operational examples and validation against field data are presented later with the Captain Fairway case (see sub-Section 4.3; Shell, 2014).

3.4. Groundwater methodologies for regional pressure modelling

Groundwater refers to the water-based fluids occupying the pore spaces and fractures of subsurface rock and sediments. It includes both freshwater present at shallow depth and deeper brines. Groundwater science offers mature methods for basin-scale flow simulation under long time horizons, with regulatory practice that treats hydraulic head as a managed, shared resource. Modular finite-difference models, such as MODLFOW and successors, are routinely calibrated against long-term water-level observations to estimate transmissivity, storativity and boundary behavior for allocation and environmental protection decisions (McDonald and Harbaugh, 1984, 2003; Department of Water and Environmental Regulation, 2024).

Integrated land–surface frameworks, such as Hydro-JULES, extend this notion by coupling subsurface flow with the terrestrial water cycle, using data assimilation to maintain temporal consistency across scales (Hughes et al., 2019). The parallels to CO_2 storage are direct: pressure budgets can be forecast and allocated when models are tied to observation networks and updated as new data arrive. Differences remain in physics and monitoring density, and some groundwater simplifications—homogeneity, isotropy and sparse representation of fractures or unsaturated flow—must be addressed when translating to deep, multi-use basins. Nonetheless, the calibration and forecasting workflows to support governance logic is transferable.

3.5. Data integration and monitoring

Regional models are only as reliable as the data that inform connectivity and hydraulic properties. In data-poor offshore settings and in newly licensed areas, uncertainty in permeability, vertical communication and far-field boundary conditions dominates forecast spread. This motivates monitoring networks that capture both the local injection response and the regional background against which interference is detected, and models are calibrated.

3.5.1. Monitoring for pressure management

Pressure is the primary observable for regional calibration. Downhole quartz gauges offer the most direct measurement of formation pressure but have finite lifetimes at high temperature and can drift; they are nonetheless invaluable when installed in injectors, producers, or dedicated observation wells during appraisal and operations.

Where downhole sensors are not available on water injectors, wellhead pressure can serve as a proxy, but falloff tests that record shut-in bottomhole pressure are far more diagnostic because they decouple reservoir response from rate-dependent wellbore effects. In practice, the least expensive network starts with the injection wells themselves, augmented by opportunistic use of offset wells in legacy fields to detect far-field interference. Regulatory programs already recognize this value: the U.S. Underground Injection Control program requires regular reporting of pressures and, for some classes, annual falloff tests that have been used to detect interference from distant high-rate injections and to quantify regional pressurization trends (Safe Drinking Water Act, 1974; Council, 2018; Ge et al., 2022).

Fig. 6 shows an example from east Texas, where a long-running waste disposal well (WDW), WDW-243, experienced interference from new, high-volume saltwater disposal wells, starting in about 2006. The graph displays both the flowing bottomhole injection pressure corrected for skin factor, and the shut-in bottom hole pressure (SIBHP), both derived from annual pressure falloff tests. The average injection rate was about 9.08m^3/hour (40 gallons per minute), and reservoir pressure rose by <100 psi from 1998 to 2005, as shown by the annual SIBHP measurements. From about 2006, however, a series of new saltwater disposal wells began injecting into the same reservoir at rates of 22.71–45.42 m^3/hour (100–200 gallons per minute), 10–20 km from WDW-243. The combined injection triggered a rapid buildup of reservoir pressure. While pressure rise is evident in both the flowing and shut-in curves, it is far clearer from the shut-in curve, which is less affected by fluctuating injection rate (see Council, 2018 for a higher-frequency injection pressure curve, which shows month-to-month variations as high as 4 MPa).

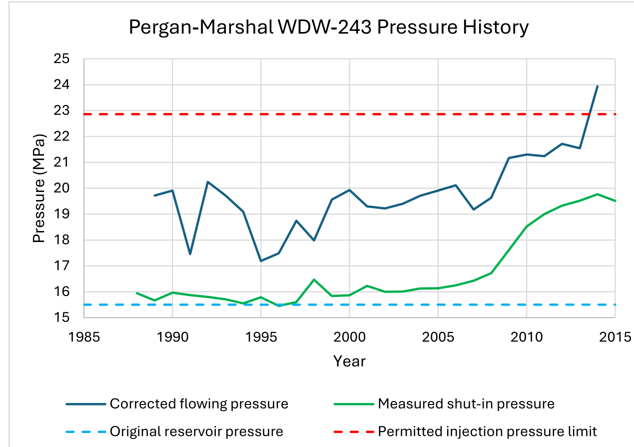


Fig. 6. Graph of injection pressures for Pergan-Marshal Waste Disposal Well 243 (WDW-243), injecting industrial waste from peroxide manufacturing. All pressures are derived from annual pressure falloff tests and corrected to bottom-hole conditions without skin. Competing high-rate saltwater disposal wells came online between March 2006 and January 2008. Note the resulting rise in reservoir pressure, starting in 2006. Data replotted from Council, 2018.

For Class VI CO_2 storage, operators typically monitor bottomhole pressure in injectors, and adding periodic falloff tests provides regional value disproportionate to cost.

Direct measurement is not the only way to estimate pressure. In the right geographical, geological and geomechanical setting, pressure changes can lead to surface deformation that can be measured using high precision geodetic techniques such as high precision GNSS and InSAR (Interferometric Synthetic Aperture Radar). InSAR is deployed at the Gorgon CCS project on Barrow Island (Jiang et.al., 2025) to measure the pressure impact of CO_2 injection. Similarly, timelapse seismic monitoring can, in the right setting, also give indications of pressure changes, as demonstrated at the Snøhvit CO_2 injection operation (White et al., 2018).

Where induced seismicity is a concern, background microseismic monitoring adds an orthogonal constraint on evolving stress, particularly in areas of known faulting or rapid rate escalation (Weingarten et al., 2015; Hennings et al., 2019, 2023).

3.5.2. Calibration and uncertainty management: Integrated regional models and digital twins for pressure management

Calibration and forecasting benefit from treating the regional model as a living digital asset where field data is assimilated with simulations as they arrive. History matching and Bayesian or likelihood-free inference methods adjust uncertain connectivity and property fields to reproduce observed pressures, rates, and, where available, time-lapse geophysical indicators of pressure change.

Digital twin workflows close the loop between observation and prediction by updating state and parameters, including their uncertainties, on a cadence aligned with field reporting, enabling scenario testing and risk quantification with uncertainty bounds that reflect data density and model identifiability (Gahlot et al., 2025; Teng and Durlofsky, 2025). For regional modelling, the frequency of model updating will be a longer time horizon, likely an annual basis, with the purpose of enabling coordination between commercial actors and regulatory/licensing activity. In offshore provinces, where dedicated monitoring is sparse and inter-site interactions may be poorly instrumented, twins that pool anonymized operator data can provide the only coherent basin-wide pressure evolution, interference of risk, and decision making under uncertainty.

3.6. Importance of shared data and open science

Trustworthy regional models depend on timely, standardized reporting and on open/shared, reproducible methods. Three elements are decisive. Firstly, there must be regular disclosure of injection and production volumes, wellhead and downhole pressures, and results of falloff tests, with appropriate cadence to inform allocation and interference decisions and coordination as hubs evolve.

Secondly, models, inversion, and data-assimilation workflows, and uncertainty quantification should be benchmarked on shared datasets so that methodological claims can be independently reproduced. Several CCS-specific initiatives exemplify this shift toward openness:

- CO_2 Data Share (SINTEF / NETL): Provides benchmark datasets from field and synthetic studies, including pressure, saturation and geomechanical data. These datasets are valuable for testing inversion workflows and simulation tools, though coverage is limited to a few well-characterized sites.
- CO_2 Storage Atlas (e.g. UK, Norway, US): Offers regional geological and capacity data for prospective storage formations. While useful for screening and conceptual modelling, these atlases often lack dynamic pressure data and detailed connectivity information needed for regional-scale simulations.
- CO_2Stop (EU project): Developed probabilistic estimates of storage capacity across Europe using standardized workflows. It provides a harmonized view of geological potential, but its resolution and assumptions may not be sufficient for pressure interference modelling or calibration of the digital twin's uncertainty.
- WISE (Yin et al., 2024): Applies ensemble-regularized simulation-based inference to seismic waveform data, generating probabilistic models of reservoir properties—particularly permeability. Its open-source implementation and synthetic datasets make it a reproducible and extensible platform for building and testing digital twins.
- Uncertainty-aware digital shadow (Gahlot et al., 2025): Includes open-source software and demonstrates how time-lapse seismic and wellbore data can be integrated to update pressure and saturation forecasts in offshore settings. While current proofs of principle of digital twins for pressure management operate at the timescale of collecting seismic surveys, developments are underway to incorporate continuous recordings, so near-realtime control can be effectuated.
- Permeability inversion (Louboutin et al., 2023; Yin et al., 2024): By making use of multi-physics full-waveform inversion of time-lapse seismic data, the reservoir's permeability can be inverted in areas occupied by flow. While initial simulation studies are encouraging, this approach needs to be validated on field data and extended to include uncertainty. In this way, the digital twin's probabilistic characterization of the reservoir can be improved as operations proceed.
- GSEU (Geological Service for Europe): Provides a foundational framework to strengthen subsurface modelling capabilities across Europe, enabling cross-sector mapping (groundwater, CO_2 storage, geothermal energy, hydrogen storage…). By harmonizing datasets through the European Geological Data Infrastructure (EGDI), GSEU enables more consistent and interoperable approaches to pressure and resource management, and the development of reference models for cross-border aquifers and storage formations.
- The UK (and others) National Data Repositories. In the UK, the North Sea Transition Authority maintains a repository of seismic data collected in the North Sea and made it available to the public. Efforts are underway to curate this dataset and integrate it with well-log data made available by the British Geological Survey. After curation is complete, this curated training dataset will be made available, so generative neural networks can be trained to establish probabilistic baselines for reservoir and seismic properties that can be used for CCS and seismic simulations and as initial models for digital twins.

Thirdly, basin-scale models benefit from regulator leadership, both to integrate proprietary operator data under confidentiality protections and to maintain a single source of truth for allocation, sequencing, and environmental safeguards. The Perth Regional Aquifer Modelling System provides a longstanding analogue for this kind of regulator-led basin model in groundwater, and the same logic applies to offshore CCS provinces where multiple users share pressure space (Department of Water and Environmental Regulation, 2024). Without shared data and open practices, regional models become unverifiable and pressure budgets cannot be credibly allocated; with them, digital twins evolve into trusted decision-support systems that keep operations within geomechanical limits while maximizing storage across the commons.

4. Illustrative examples of regional pressures studies

Regional-scale modelling clarifies how pressure propagates through connected formations and how multiple activities interact in space and time, well beyond individual lease boundaries. The following three cases – the Horda Platform in the Norwegian North Sea, the Paris Basin in France, and the Captain Fairway in the UK Continental Shelf - span contrasting geological settings, boundary conditions, and development histories. Together they show that pressure footprints are much larger than CO_2 plumes, that interference can occur over tens to hundreds of kilometers, and that legacy depletion, compartmentalization, and boundary openness control both magnitude and directionality of pressure change (Zhou et al., 2008; Thibeau and Mucha, 2011; Birkholzer et al., 2009; Tveit et al. 2024; Pettersson et al. 2022; Riordan et al., 2025).

4.1. Horda platform (Norway)

The Horda Platform, located off the west coast of Norway, is a strategically important area for Norwegian storage, hosting multiple prospective storage units (EL001 (Aurora), EXL002 (Smeaheia), and EXL004 (Luna)) within a laterally extensive, faulted setting (e.g. Færseth, 1996; Odinsen et al., 2000; Bell et al., 2014; Duffy et al., 2015) that also includes major hydrocarbon assets such as the Troll field. This coexistence raises a practical question: how will pressure behave when CO_2 injection proceeds in a region already conditioned by decades of production and depletion, and how will that behavior affect interference risk and storage allocation across licenses?

A regional model was developed using the Cirrus COMP3 module (Riordan et al. 2025; Nazarian and Furre, 2022), a pseudo-compositional tool for simulating CO_2 storage in depleted gas reservoirs. It captures regional pressure response rather than detailed plume migration, so the grid prioritized lateral connectivity and structural topography, with cell sizes of 500 × 500 m and representative layering across the injection intervals (Tveit et al., 2024). It was initialized with in-place hydrocarbons and the Troll production history so that system compressibility reflects the gas cap and remaining fluids, which is essential to reproduce depletion patterns and damped pressure response compared to a brine only aquifer.

Two scenarios injecting 5 and 6.25 Mtpa respectively into the lower Viking group (Fensfjord and Krossfjord Formations) were run. The simulations show that the CO_2 plume remains comparatively local after a decade (Fig. 7-B), whereas pressure changes extend far into the Sognefjord Formation and across structural compartments (Fig. 7-D). At the injectors, pressure rises to ~30 bars by 2040 (Fig. 7-B), while regional pressure differences away from the injectors are modest compared with the existing depletion signature around Troll (Fig. 7-C). The patterns are strongly controlled by fault segmentation and mud rich barriers separating sand rich flow units; boundaries and compartmentalization limit where and how quickly pressure communicates. Because the model matches observed pressure trends over an area of ~81 × 142 km within practical runtimes (Fig. 7-A), it is fit for purpose as a decision tool: it quantifies the relative roles of legacy depletion (Fig. 7-B), compartment architecture, and injection intervals (Fig. 7-B) in shaping pressure footprints and helps operators and regulators identify where interference is most likely (Riordan et al., 2025; Birkholzer and Zhou, 2009).

4.2. Paris basin (France)

The Paris Basin offers a contrasting onshore case with laterally extensive, well connected Jurassic saline aquifers overlain by an efficient regional seal, and with a long history of subsurface use for hydrocarbons and geothermal energy (Wendebourg and Lamiraux, 2002; BRGM, 2024; Hanot, 2025). According to a recent nationwide assessment of GCS potential, these same units could accommodate 9.6 Mt of CO_2 in depleted reservoirs and 340 Mt of CO_2 in saline aquifers (Guillon and Bossie-Codreanu, 2025; Burnol et al., 2025). The central question here is how a seemingly uniform, high quality stratigraphic aquifer responds to multi-site CO_2 injection at basin scale once facies transitions and regional boundaries are accounted for.

A basin model spanning ~570 × 435 km and ~3.3 km maximum thickness was constructed from the Carboniferous basement to the Tertiary cover; petrophysical distributions were estimated via basin modelling consistent with burial and thermal history, and Bathonian aquifers received high vertical resolution due to their CO_2-storage relevance (Ungerer et al., 1990; Teles et al., 2014; Torelli et al., 2020). Two phase Darcy simulations in TemisFlow tested injection of 1 Mtpa for 50 years at three former license areas.

The results show a clear divergence between plume and pressure behavior. While individual CO_2 plumes remain confined to a few kilometers around injection sites, the pressure plume extends beyond 250 km over the 50-year horizon, with dissipation and diversion governed by basin geometry and facies architecture (Fig. 8). To the east, the lack of a sealing barrier allows upward dissipation and a milder pressure rise; to the west, a thick marly barrier inhibits dissipation locally and directs pressure northward, although pressure increments remain <10 bar in the far field. Pressure fields from sites up to ~120 km apart eventually overlap, forming a single regional pressure footprint. This case demonstrates that even in apparently uniform stratigraphic settings, modest facies changes and boundary conditions create strong anisotropy in pressure propagation, reinforcing the need for basin-wide models when planning multi-site operations (Mattioni et al., 2022; Burnol et al., 2025; Guillon and Bossie-Codreanu, 2025).

4.3. Captain fairway (UK)

The Captain Sandstone Formation in the Outer Moray Firth is a characteristic regional aquifer within Cretaceous-age strata, with local narrowing into a "fairway" and thick low-permeability seals, and it hosts both depleted and producing hydrocarbon fields. The practical question addressed by the CO_2MultiStore project was whether multiple CO_2 injections within this connected pore volume would interfere, over what distances, and how earlier operations would condition later storage capacity (Scottish Carbon Capture and Storage SCCS, 2015; Jin et al., 2012; Akhurst et al., 2015).

A geological model was created by merging published static models with operator data for Goldeneye, treating the Lower Captain Sandstone as laterally continuous across the east–west extent and assuming over- and under-burden formations are effectively impermeable for the pressure timescales of interest. A regional dynamic model, similar in scope to the one later documented in Shell's Peterhead CCS Dynamic Modelling Report, was used to history-match field pressure and then forward-simulate injection scenarios in accordance with EU Storage Directive requirements (Shell, 2014; European Commission, 2009/31/EC).

Two 30- yr, 6 Mtpa injection scenarios were tested: Site A at Goldeneye (2016–2046) and, with a 5-year lag, Site B between Cromarty and Blake (2021–2051). Observations along a 90 km west–east transect show that nine years of Goldeneye production reduced pressure at Site A by ~10 MPa relative to hydrostatic; during the five year pause before CO_2 injection, aquifer recharge increased pressure by ~3 MPa, reducing available "pressure space." Injection at Site A then raised pressure by ~7 MPa above initial levels near Goldeneye and returned Site B to hydrostatic from a ~1 MPa production depleted state. Importantly, responses east of Site A were significantly larger than to the west, consistent with a more closed aquifer to the east and an outcropping, more open boundary to the west (Figs. 9, 10).

Interference effects were evident over at least ~45 km, and the analysis showed that pressure space created by depletion can be partially lost by recharge if not utilized promptly. This case underscores three design lessons that generalize to other basins with mixed boundaries and legacy production: interference distances can be large; boundary openness and dip direction set asymmetric responses; and timing between cessation of production and onset of injection materially affects realized capacity (Thibeau et al., 2014; Cotton et al., 2017).

4.4. Solving the co-existence conundrum: to unitize or not to unitize?

The previous examples reveal a consistent feature of pressure-connected systems: one operator's decisions alter the feasible operating window of others. Where multiple operators inject into the same hydraulic unit, efficiency and fairness depend on how the shared pressure budget is allocated and whether they coordinate or compete. However, because the projects are in competition, there does not exist a perfectly optimal allocation that can satisfy all actors simultaneously. In fact, there are infinite number of agreements that could be formed, each involving certain trade-offs.

Cooperative game-theoretic analyses applied to geological storage offers a useful framework for providing valuable insight in these situations. The trade-offs are formalized by mapping the set of efficient allocations, those where no agent can improve without harming another, and by quantifying how coalition structures shift both individual outcomes and total stored mass (Pettersson et al., 2024, 2025).

In a Norwegian case study with three competing agents (Fig. 11), social-welfare maximization (which is the allocation that brings each agent as close as possible to their individual maximums simultaneously) achieved the largest total storage across agents. The shares allocated to each agent in this allocation option are remarkably insensitive to whether they formally cooperated, implying that coordination or regulation can deliver system-level efficiency without necessarily granting outsized commercial advantages to coalitions. Conversely, allocations that favor a single agent typically reduce total storage, with the magnitude of loss depending on spatial configuration and boundary conditions. These insights, while model-dependent and subject to geological uncertainty, provide a quantitative language for regulators and consortia to weigh trade-offs among efficiency, equity, and first-mover incentives when setting license terms, quotas, sequencing of projects, or brine-production obligations in a pressure-limited commons.

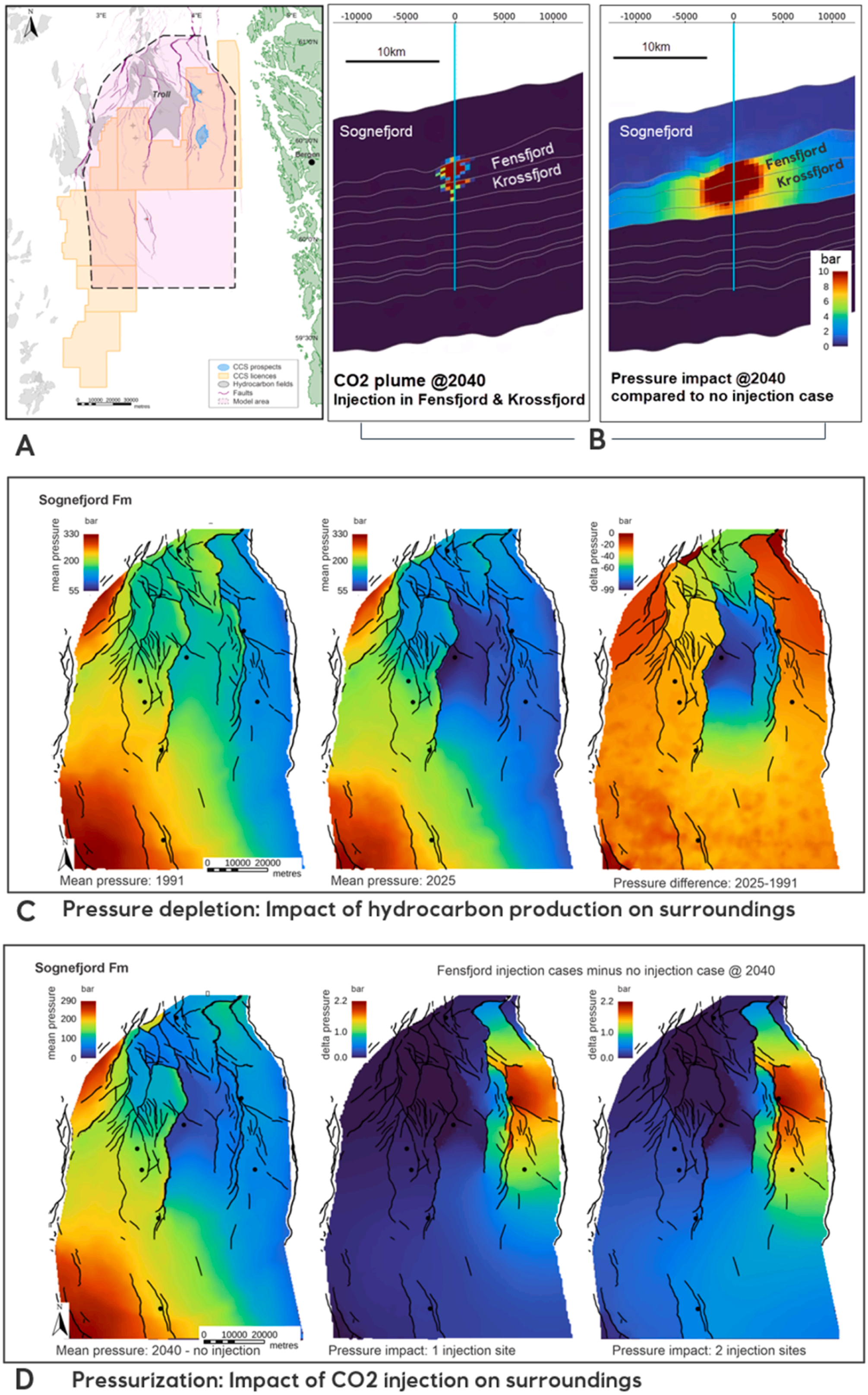


Fig. 7. Pressure depletion from existing hydrocarbon fields and introducing CO_2 injection into the shared pressure space (Riordan et al., 2025). **A.** Model area including CCS licenses and hydrocarbon fields on the Horda platform. **B.** CO_2 plume versus pressure plume: pressure effects of injection in the Fensfjord Formation on the overlying the Sognefjord fm. **C.** Pressure depletion in the Sognefjord Formation due to hydrocarbon production from the Troll field. **D.** 1) expected pressure in 2040 with no CO_2 injection; 2) pressure difference map showing the effect of one injection site on the pressure space; 3) pressure difference map showing the effect of two injection sites. Note: Injection from the Aurora license was not included in the simulation cases.

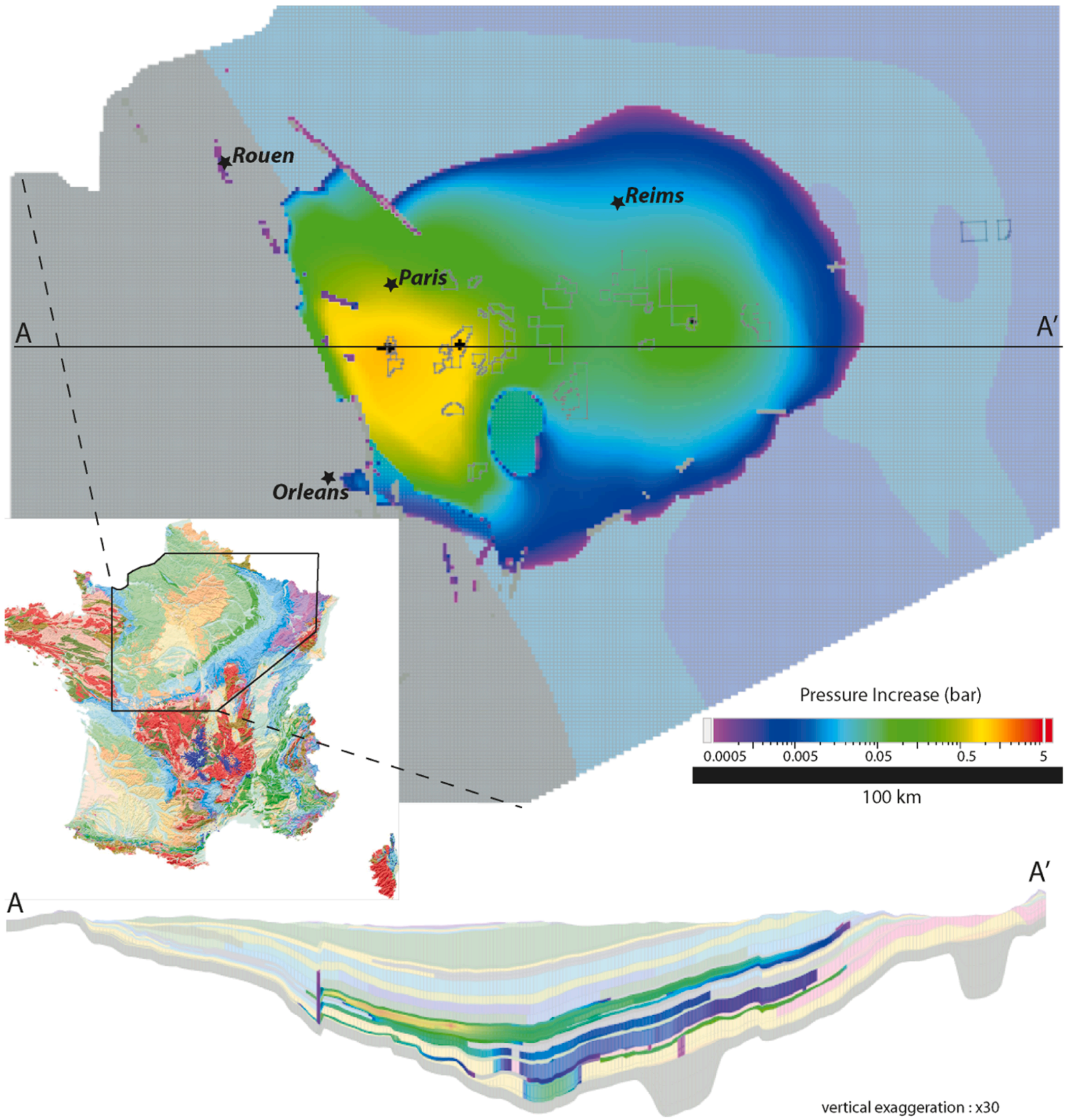


Fig. 8. Numerical simulation results considering the injection of 1 Mtpa of CO_2 over 50 years in three former oil and gas concessions in the Bathonian saline aquifer of Paris Basin. The results are presented at the end of the 50-year injection. The model location is shown on the geological map of France (@BRGM). Top map displays the facies map of the lower Bathonian interval in the background. The grey color corresponds to the marly facies, and the blue color corresponds to carbonate reservoir facies. The pressure plume is represented in the main color gradient, together with the CO_2 plume (small black cells), as well as in the A-A' section.

4.5. *Groundwater resources management as an analogue*

Groundwater management treats hydraulic head as a finite, regulated resource supported by basin-scale models, long-term observation networks, required reporting, and adaptive rules—an institutional architecture directly relevant to CO_2 storage pressure management. Regulator-led systems such as the Perth Regional Aquifer Modelling System (PRAMS) calibrate transmissivity, storativity and boundaries against monitored heads, (directly related to aquifer water pressure), and then use the calibrated model to allocate pumping, protect environmental thresholds, and update decisions as new data arrive (McDonald and Harbaugh, 1984, 2003; Department of Water and Environmental Regulation, 2024). Integrated land–surface frameworks such as Hydro-JULES extend this by coupling subsurface flow to the terrestrial water cycle and applying data assimilation to maintain temporal consistency across scales, demonstrating how multi-agency data and open infrastructures can underpin credible, adaptive resource governance (Hughes et al., 2019).

Translating this analogue to CO_2 storage means treating pressure budgets as allocable, updating regional models with periodic falloff tests and rate/pressure reporting, and using digital-twin workflows to test alternative operational levers—spacing, rate governance, sequencing or brine extraction—before acting. The physics differs in detail, particularly multiphase flow and geomechanical coupling in deep saline systems, but the governance logic is the same: credible regional models tied to monitoring enable sustainable allocations and coordinated responses as interference emerges (Thibeau et al., 2014; Pettersson et al., 2025).

5. Water production (Brine extraction) as a pressure-management solution

Water (brine) production has been proposed as a method to expand pressure space. Conceptually, extracting formation water creates voidage that offsets injection induced pressurization. This concept is essentially the inverse of water injection during hydrocarbon production and has been discussed for more than a decade in strategic assessments

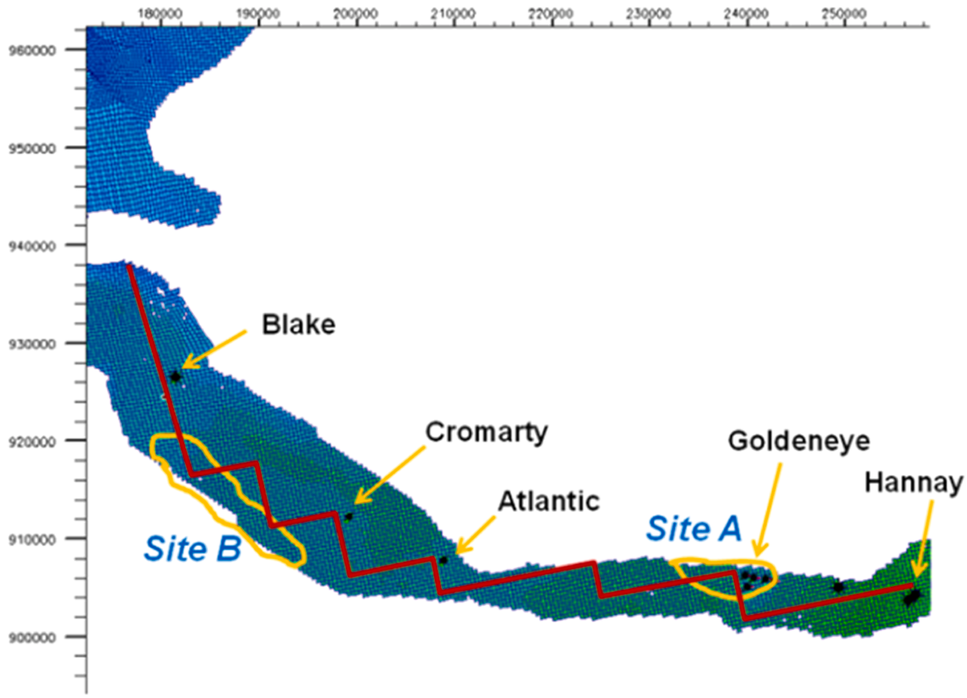


Fig. 9. Principal study area in the Captain sandstone Formation for the CO_2MultiStore project, showing producing and depleted fields, and two proposed CO_2 storage sites: Site A (Goldeneye) and Site B. The red line marks the west–east transect used for pressure modelling in Fig. 11. Colors indicate initial hydrostatic pressure, ranging from 15 MPa (blue, west) to 30 MPa (green, east).

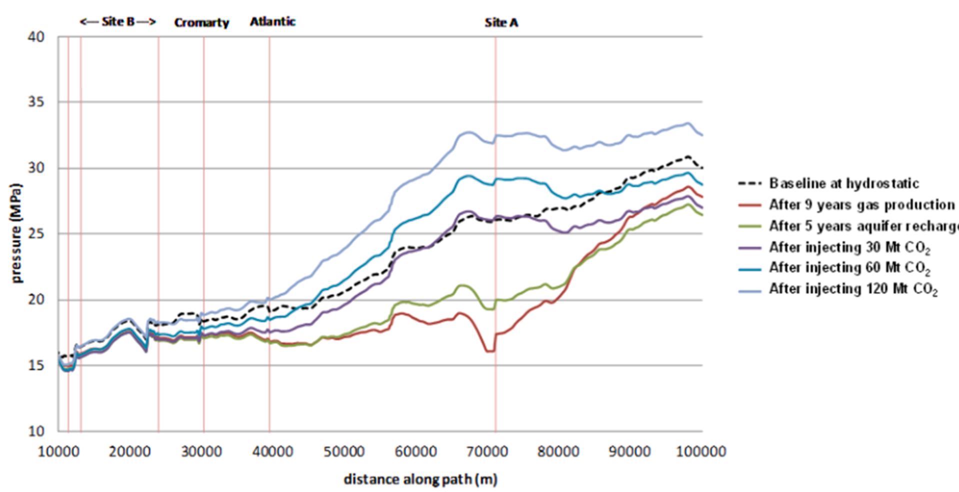
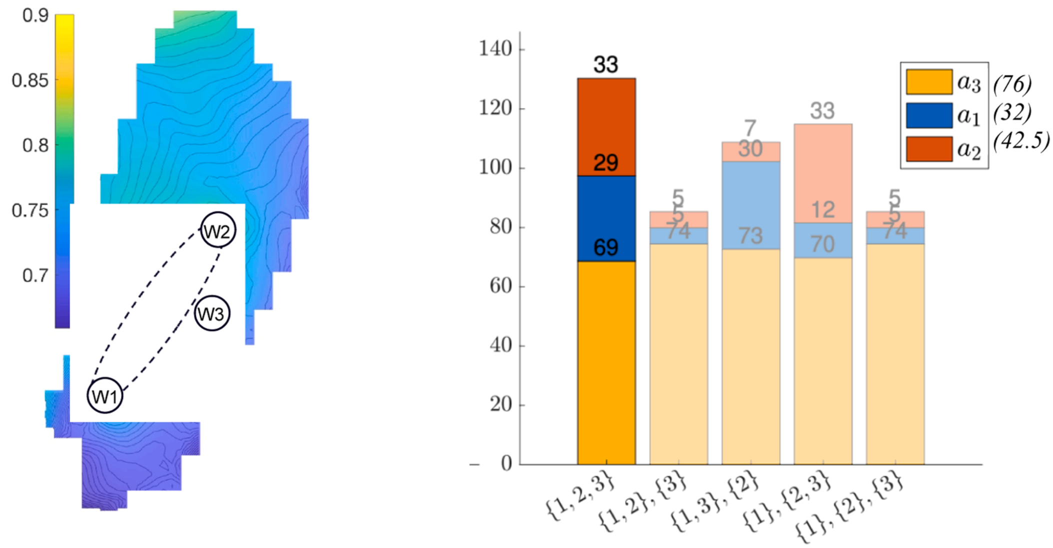


Fig. 10. Pressure profiles along the 90 km west–east transect shown in Fig. 9, illustrating CO_2 injection at Site A (Goldeneye) at 6 Mtpa. The dotted line marks pre-production hydrostatic equilibrium in 2002. Owing to structural dip, hydrostatic pressure increases eastward. After nine years of production, pressure at Goldeneye dropped by 10 MPa, followed by a 3 MPa recharge during the five-year pause before injection. By year five of injection, pressure at Goldeneye returned to hydrostatic levels, while Site B remained 1 MPa below equilibrium due to earlier production effects. Model results align with downhole pressure data, including during aquifer recharge.

and reservoir studies (SCCS, 2009; 2011; Buscheck et al., 2016; Energy Technologies Institute, 2018). By reducing net pressure rise, brine production can stabilize injectivity, shrink the regional pressure footprint, and reduce the potential for expulsion of fluid through faults or legacy wells. These benefits extend beyond the local lease: a single strategically placed producer can influence pressure behavior across tens of kilometers, as demonstrated in regional models (in Section 4).

Field experience though remains limited. The Gorgon Project in Western Australia is the only commercial CCS development to implement large-scale brine extraction, reinjecting produced water into a shallower formation to maintain pressure within regulatory limits (Trupp et al., 2021; Weijermars, 2024). Operational challenges—such as sand control, scaling, and corrosion—must be engineered for multi-decadal timelines, and brine handling requires early integration into project design. Offshore, OSPAR (2025) rules in the North Atlantic prohibit CO_2 discharge to the water column but allow brine reinjection into suitable formations; surface discharge is possible only under strict treatment and monitoring regimes, as in oil and gas operations. These constraints make reinjection the default option in many jurisdictions.

The planning implications are significant. First, brine production can unlock capacity in pressure-limited settings, enable higher injection rates as new CO_2 sources come online, and extend the operational life of



(a) Optimal well locations in Bjarmeland formation

(b) Total CO_2 stored in different 3-agent coalitions

Fig. 11. Example of cooperative game theory analysis for GCS for a fictitious case of three agents – a1, a2 and a3 – with individual maximums given in parentheses in the legend. Shown on the left are the well locations in the Bjarmeland formation, Norway. Reservoir simulations are used to map the space of possible efficient allocations, resulting in a set of Pareto fronts (not shown). The data are used to examine the amount of CO_2 stored for each agent for two different allocation scenarios, as depicted in the column plot (right). The left-most column gives CO_2 stored per agent for the social welfare maximization scenario; the next four columns (light-shaded) show four possible allocations favoring agent 3. The total CO_2 stored is highest for the social-welfare maximation scenario even though agent 3 can get marginally more value in scenarios where they are favored. Adapted from Petersson et al., (2025).

a store. It can also reduce post-closure pressure more rapidly, potentially shortening monitoring obligations and liability periods. Fig. 12 illustrates this, e.g., a UKCS sandstone scenario shows a ~40 bar reduction in peak pressure over a 40-year injection period with one producer, and post-injection drawdown returning pressure to within ~10 bar of baseline when production continues after injection—illustrative of the magnitude of effect in pressure-limited settings.

Secondly, asset context matters. Depleted or waterflooded hydrocarbon systems have greater compressibility than brine-saturated equivalents, meaning pressure communication with such formations can dampen pressure rise from CO_2 injection. If CO_2 contacts hydrocarbons, its solubility is typically higher than in brine, enhancing solubility trapping. However, caution is needed if hydrocarbons are mobile or become mobilized, as this could increase plume migration (Ghanbari et al., 2020). Voidage from hydrocarbon production might substitute for brine extraction, though benefits would depend on the degree of

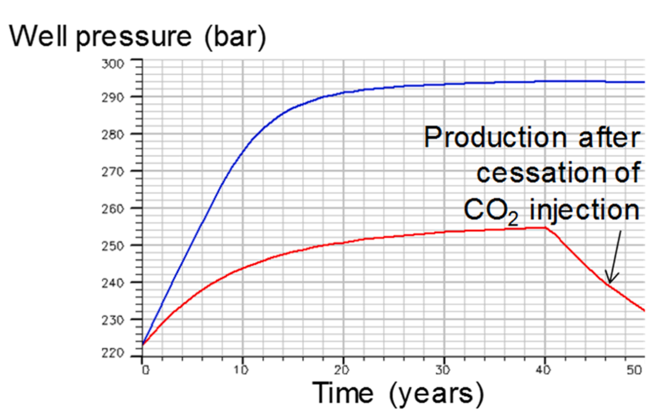


Fig. 12. Example of well bottom hole pressure calculation for a CO_2 injection well with (red line) and without (blue line) brine production (at a distance that precludes CO_2 breakthrough to the production well). Note that continued production beyond the 40-year CO_2 injection period allows for pressure reduction, with accompanying reduction of leakage risk, etc.

pressure communication and project spacing. Monitoring and monetizing such interactions would be complex and time dependent.

Overall, these benefits depend on system connectivity, regulatory acceptance and the economics of water handling. Regional models are essential for quantifying the value of pressure relief and for optimizing producer placement relative to injectors and boundaries. When integrated into licensing frameworks, brine production becomes a governance lever: regulators can require or incentivize pressure-management wells as part of a basin-wide allocation strategy (further discussed in Section 6). Treating pressure space as an economic asset—and designing enhanced-voidage wells to oilfield standards—will be critical for scaling CO_2 storage safely and efficiently.

6. Regulation and governance for pressure management

Based on the key points from the previous sections, it is clear that pressure constrains the collective resource available for GCS in saline formations. Petroleum Engineers have been aware of interference between fields since the 1950s (see for example Rumble et al., 1951), but the production of petroleum is, initially at least, dominated by the energy from highly compressible petroleum fluids. Rules for petroleum production focus on the mineral resource, and not on the aquifer that surrounds the resource. Most CO_2 storage regulations have been adapted from petroleum laws (e.g. The Offshore Petroleum and Greenhouse Gas Storage Act 2006 in Australia, and the Energy Act 2008 in the UK) and are focused on the injected CO_2 and not the saline formation into which it is injected.

The urgency of climate targets and the rapid build-out of shared transport infrastructure amplify the challenge of managing the pressure resource: decisions made in isolation risk locking in inefficiencies and could lead to stranded assets. Project developers need confidence that they will be able to inject the volumes requested by emitters at the required rates. Effective governance must therefore move beyond site-scale CO_2 containment to basin-scale coordination, embedding pressure limits into licensing, monitoring and allocation frameworks.

Several regulatory precedents point the way. In the UK, the North Sea Transition Authority Carbon Storage Licensing (2025) now requires storage licenses to retain and report operational data, with provisions for staged public disclosure to accelerate learning and maximize storage potential. Groundwater regulators have long operated basin-scale models to allocate pumping rights and protect environmental thresholds; the same logic applies offshore, where regulator-led models can integrate operator data under confidentiality protections and provide a single source of truth for pressure budgets and interference risk. Similar approaches underpin the Perth Regional Aquifer Modelling System in Western Australia and could be adapted for CCS provinces.

Other policy levers that could be deployed are suggested below:

- Pressure reporting. Require periodic reporting of static downhole pressures (preferably in the water leg) and injection/production volumes from all permitted wells—not just CO_2 injectors—to support regional model updates and conformance checks. The UK's data retention/disclosure framework provides a template for codifying these expectations.
- Microseismicity monitoring and pooled event databases. It has been demonstrated in the US state of Oklahoma that injection into the subsurface can induce seismic events. Early detection of events below the human nuisance threshold can allow regulators and operators to modify injection plans, or install water extraction, before felt events take place (Zarifi et al., 2023).
- Regional modeling as a license condition. Require or maintain regulator-led regional models that assimilate operator data (with appropriate confidentiality protection or anonymization) to allocate pressure budgets, evaluate cumulative effects, and sequence licensing. Groundwater regulators have operated this way for decades (e.g., PRAMS), demonstrating feasibility and public value.
- Capacity screening via material balance. Before awarding new acreage, perform first-order pressure-capacity screens (pore volume, compressibility, boundary conditions) to avoid over-allocating in a pressure-limited system; defer licensing in highly uncertain aquifers until observed pressure response from early movers reduces uncertainty. This mirrors regulator practice in groundwater allocation programs.
- Brine production within permits. Depending on the technical and cost considerations, enable dialogue between the users to investigate environmentally compliant re-injection or disposal of brine as a part of pressure management plans and/or remedial options. What is critical here is to establish an equitable way to allocate the costs of brine management, to avoid free-loading, and to protect the investments already made by earlier projects in a storage formation.
- Cross-border/regional alignment. In multi-jurisdictional basins, align monitoring, reporting and modeling interfaces (data formats, update frequency, confidentiality windows) to ensure pressure footprints and safe-operating windows are coherently managed across boundaries.

Effective MMV, open data and digital infrastructures are critical enablers. Without timely sharing of pressure and rate data, local models rely on assumptions that cannot capture dynamic interference, undermining both safety and efficiency. Ideally, shared data will allow the development of digital twins that, thanks to their principled handling of uncertainty in the static reservoir properties, rock physics, and seismic imaging, can assimilate observations, update forecasts, and inform adaptive management of pressure budgets. This would reduce the risk of stores being shut in, damaging project economics, as a result of induced seismicity or brine leakage.

The challenge will be in the local implementation of a regional management strategy, especially in areas where storage formations are owned by multiple parties or cross regulatory or sovereign boundaries. That said, governance needs to work out pragmatic solutions to treat pressure space as an allocable, monitored commodity, managed transparently and adaptively to unlock gigatonne-scale GCS while safeguarding environmental integrity and ensuring fair access across users.

7. Outlook: A commons-based future

The rapid scale-up of geological CO_2 storage is transforming the deep subsurface into a shared, multi-use domain. As injection volumes rise and new activities, such as geothermal energy, hydrogen storage, and critical mineral extraction, enter the same formations, coexistence is no longer optional. We demonstrated here that pressure is the true limiting resource: it propagates quickly, crosses lease boundaries, and accumulates over time. We then argue that treating pressure as a managed commons, rather than an incidental byproduct, is essential for safe and efficient deployment. While GCS has historically looked to petroleum legislation for inspiration, it now needs to look to groundwater legislation for further improvement.

The next decade will determine whether this transition succeeds. Four questions stand out. Firstly: how can we quantify pressure budgets and safe operating envelopes at basin scale under uncertainty, and update them as new data arrive? Secondly: what constitutes a minimum viable monitoring network (pressure, injection rates, and microseismicity) that enables storage formation wide digital twins on land and offshore? Thirdly: which combination of operational tools (spacing, rate governance, sequencing and brine extraction) delivers the best trade-off between storage efficiency and risk under different boundary conditions? Finally, in each commercial and regulatory setting, which allocation mechanisms (unitization, quotas, auctions or cooperative game-theoretic frameworks) balance efficiency, fairness and first-mover incentives in pressure-limited systems, allowing businesses to effectively develop cost effective and financeable storage projects?

Answering these questions requires more than technical innovation. It demands institutional frameworks that embed pressure limits into licensing, collaboration between storage operators and other users of the subsurface, timely data sharing, and the maintenance of formation-wide, history matched regional models as a public good. Digital twins should evolve from project-scale pilots to basin-scale decision platforms, assimilating observations in near real time and supporting adaptive allocation. Groundwater management offers a compelling precedent: decades of practice show that basin-scale models, effective MMV, open data, and enforceable reporting can sustain a finite resource under competing demands. The same principles, adapted for multiphase flow and geomechanical coupling, can futureproof the deep subsurface. This is not simply about storing carbon dioxide; it is about building a governance architecture that secures climate goals, delivers economically efficient storage project, and maintains environmental integrity in a very large but still finite, interconnected geological system.

CRediT authorship contribution statement

Audrey Ougier-Simonin: Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Resources, Conceptualization. **Owain Tucker:** Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Conceptualization. **Alexander Bump:** Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Conceptualization. **Sarah Eileen Gasda:** Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Conceptualization. **Rannveig Elise Otterlei:** Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Conceptualization. **Adriana Lemgruber-Traby:** Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Conceptualization. **Eric Mackay:** Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Conceptualization. **Ludovic Paul Ricard:** Writing – review & editing, Writing – original draft, Visualization, Resources, Methodology, Conceptualization. **Felix Herrmann:** Writing – review & editing, Writing – original draft, Visualization, Resources, Methodology, Conceptualization. **Matthias Imhof:** Writing – review & editing, Supervision, Resources, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

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Data availability

No data was used for the research described in the article.

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