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Review article

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Subsurface carbon dioxide and hydrogen storage for a sustainable energy future

Samuel Krevor[1], Heleen de Coninck[2,3], Sarah E. Gasda[4], Navraj Singh Ghaleigh[5], Vincent de Gooyert[6], Hadi Hajibeygi[7], Ruben Juanes[8,9], Jerome Neufeld[10,11], Jennifer J. Roberts[12] & Floris Swennenhuis[3,6]

Abstract

Gigatonne scale geological storage of carbon dioxide and energy (such as hydrogen) will be central aspects of a sustainable energy future, both for mitigating CO_2 emissions and providing seasonal-based green energy provisions. In this Review, we evaluate the feasibility and challenges of expanding subsurface carbon dioxide storage into a global-scale business, and explore how this experience can be exploited to accelerate the development of underground hydrogen storage. Carbon storage is technically and commercially successful at the megatonne scale, with current projects mitigating approximately 30 Mt of CO_2 per year. However, limiting anthropogenic warming to 1.5°C could require gigatonnes of storage per year by 2050, and a scaleup from 2025 approaching rates of deployment that would be historic for energy technology. Scale-up is not limited by geology or engineering. Advances in understanding storage complex geology, subsurface fluid dynamics, and seismic risk underpin new engineering strategies including the development of multi-site, basin scale, storage resource management. Instead economic and societal contraints pose barriers to project development. Underground hydrogen storage, still in development, will face similar issues. Overcoming these barriers with strengthened financial incentives, and programs to address concerns inhibiting public acceptance, will enable the storage of CO_2 at climate relevant scales.

Sections

A full list of affiliations appears at the end of the paper. e-mail: skrevor@imperial.ac.uk

Key points

- Subsurface carbon dioxide storage is deployed at industrial scales in various geological, socio-economic and technological contexts. Climate change mitigation scenarios project that CO_2 storage will be an ongoing, rather than a transitionary, contributor to the energy transition, providing gigatonnes of CO_2 mitigation per year.

- The geological understanding of CO_2 storage sites uses the concept of the storage complex, including fault compartmentalized systems and residual and dissolution trapping for injected plume immobilization. Advances in understanding injected CO_2 plume dynamics and reservoir mechanics open the possibility of predictive modelling of CO_2 flow and proactive management of seismicity to ensure safe operation.

- Underground hydrogen storage (UHS) is a prospect for temporary or seasonal-based terawatt-scale energy storage, similar to natural gas storage. However, the technology is in the early development stage, and the immediate challenges of UHS are addressing uncertainties in the flow properties, storage integrity and the management of microbial degradation of stored H_2.

- Although CO_2 storage scale-up is not unduly limited by geological or engineering constraints, both public awareness and acceptance are low. Leading concerns are focused on leakage and seismicity, the continued dependence on fossil-fuel technologies and lack of trust in project operators. UHS could face many of the same concerns.

- Market-based policy support in the USA, Canada and Norway in the form of tax incentives and carbon credits has led to the emergence of viable business models. The policies and the strength of support in the USA, Canada, and Norway should be considered by other governments interested in scaling up CO_2 storage.

- Carbon storage is poised to have a major role, at gigatonne scales, in future climate change mitigation strategies if existing policy support can be expanded and issues of public acceptance are addressed. Deployment trajectories in integrated assessment models are unrealistic, but can be remediated with the adoption of simple growth constraints.

Introduction

To limit anthropogenic warming to 1.5–2 °C as set out in the 2015 Paris Agreement, the Intergovernmental Panel on Climate Change (IPCC) identified a series of solutions for a sustained reduction of CO_2 into the atmosphere, while still meeting energy demands through renewable sources[1]. However, anthropogenic warming is so advanced that a transition from fossil-fuel use is not enough. Scenarios limiting warming to 1.5 °C or less also require vast deployment of underground CO_2 storage of between 3 and 10 Gt CO_2 per year by 2050[1] — a rate of fluid handling on par with the present-day oil industry. The growth in industry required to achieving these vast rates of CO_2 storage by 2050 is historically unprecedented[2]. The appearance of such high rates is indicative of the enabling impact that maximising growth in the CO_2 storage industry has on achieving climate change mitigation goals. Maximising growth in turn means garnering the support of international organizations, governments, industry and the public.

Underground CO_2 storage has been a central feature of techno-economic roadmaps towards a sustainable energy future since 1995 with the Second Assessment Report of the IPCC, in which it was identified as important for mitigating emissions from power production and industries that are difficult to decarbonize[3]. Existing carbon capture and storage (CCS) projects use high-concentration emissions from industrial (such as natural gas processing) and fossil-fuel power production processes, compress and transport the captured CO_2 by pipeline and inject into porous sedimentary rocks underground, mostly depleted oil fields and sometimes saline aquifers (Fig. 1). Carbon dioxide is injected as a supercritical fluid to more than 1 km depth, in geological structures that ensure the CO_2 is trapped physically and permanently. An emerging variation of geological storage that has not reached commercial scales involves the injection of CO_2 into basalt formations to induce carbon mineralization, but this is not reviewed here (reviewed elsewhere[4]). Other forms of geological storage, including storage in oceans and coal seams, once considered to have potential, are no longer considered viable.

There are increasing examples of technical and commercial success in the execution of megatonne per year CO_2 storage projects. In 1996, the Sleipner Project began injecting CO_2 at rates close to 1 Mt per year into the Utsira Sandstone beneath the Norwegian North Sea[5]. By 2020, there were 26 commercial CCS projects, in total storing ~30–40 Mt CO_2 annually[6]. Viable business models exist in localities such as the USA and Norway. In these locations, project costs are minimized through the capture of high-concentration streams of CO_2, costs can be recovered through tax incentives or revenue from oil production, and legal frameworks provide clear guidance on permitting and liability.

Despite the demonstrated potential of CCS, far more projects were ultimately halted owing to a range of social, economic, legal, political, engineering and geophysical barriers[7]. As such, there remains substantial uncertainty around the feasibility of achieving gigatonne-scale CO_2 storage by 2050. In the run up to 2025–2030, increased policy support will be necessary to enable business models across a wide variety of geographies and CCS chains. It is also essential during this time for industry and government stakeholders to address major concerns of the publics, particularly over the risks of leakage and seismicity, and distrust rooted in the association between CCS and the fossil energy industry.

Advances in Earth science and engineering are already addressing issues that will become essential in the subsequent decade to 2040, as storage rates approach the gigatonne scale. New approaches in reservoir characterization and simulation are leading to accurate forecast modelling of plume behaviour[8] and the ability to simulate storage operations over basin scales[9]. The management of seismicity is shifting from a reactive to a proactive approach[10]. Targets have been identified for monitoring and mitigating CO_2 leakage from very large stores, guaranteeing rates of less than 0.01% loss of the injected volume annually[11].

The increasing need and development of CO_2 storage has also led to increased interests in geological formations as terawatt-scale energy stores. Natural gas storage (NGS) in North America and the UK has been ongoing since 1915 to buffer temporary differences between supply and demand[12]. In a similar way, underground hydrogen storage (UHS) could be used to smooth seasonal fluctuations in solar or wind energy, as green hydrogen has been identified as a leading carrier of renewable energy. A number of physical and chemical processes that may be important for hydrogen storage are currently not well understood, including the impact of microbial activity, hysteresis in fluid

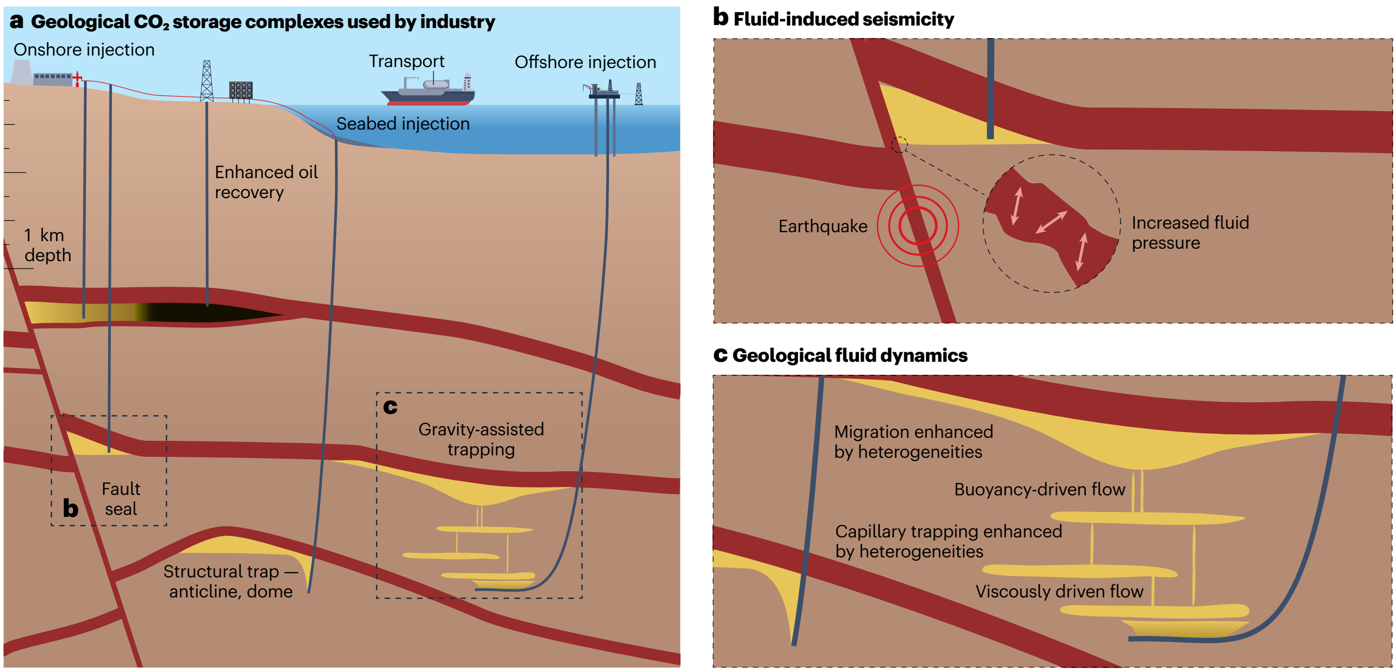

Fig. 1 | Geological underground CO_2 storage complexes used by industrial-scale projects. a, Onshore, offshore and seabed injection projects use particular geological structures to hold the captured CO_2, including a reservoir rock, caprock and trap structure (for example, a fault seal, salt dome or anticline trap) or gravity-assisted residual trapping. **b**, Inset showing how increased fluid pressure from CO_2 injection can lead to a reduction of stress along an existing fault plane, potentially causing induced seismicity. **c**, Inset showing features of reactive fluid dynamics including the impacts of reservoir heterogeneity and buoyancy on enhanced plume migration and trapping. A wide variety of geological settings and trapping mechanisms have been used for CO_2 storage to date.

flow properties and evaporative processes with salt precipitation that could affect the ease of injection and production.

In this Review, we assess the feasibility of the projected roles of CO_2 and H_2 storage in sedimentary geology in the sustainable energy transition. We discuss the diverse range of geological, technological, social, regulatory and economic contexts of underground CO_2 storage since its establishment in the 1990s[5]. Analogous subsurface fluid technologies such as hydrogen storage underground could see the benefit from the knowledge accrued from both CO_2 and NGS. We identify the key technical and socio-economic issues that will need to be addressed to enable CO_2 storage to evolve from a technology demonstrated at industrial scales today to a global-scale business rivalling the current hydrocarbon industry.

Potential and limits of the subsurface

Subsurface geology underpins the geography of storage, defines how much CO_2 can be injected and how quickly controls trapping and determines the risks of induced seismicity and CO_2 escape. This section discusses the current geological understanding of these engineered systems.

The storage complex

The geological storage complex is made up of the subsurface strata into which the CO_2 is injected and contained. The complex typically comprises a porous and permeable reservoir targeted for storing the CO_2, an impermeable overlying caprock preventing upward migration and a combination of geological structures and characteristics of the rocks that combine to ensure that the CO_2 is trapped underground permanently (Fig. 1). This combination of features occurs in sedimentary rock sequences. The geography of sedimentary basins places the uppermost bound on the global distribution of potential storage locations[13].

The lithologies of the reservoirs in which CO_2 is stored are either siliclastic (such as sandstone) or carbonate rocks. Reservoirs for existing projects have average permeability of 10^{-15} m^2 or greater, and porosity ranges 0.07 to 0.22 (ref. [14]). The reservoir rocks must be deep enough such that the injected CO_2 is in a liquid or supercritical state, typically below 800–1,000 m in the subsurface[15]. Two dominant reservoir types have been used since the mid-1990s as industrial scale storage resources: brine-filled porous rock formations known as saline aquifers, and depleted or depleting hydrocarbon fields[16]. Saline formations offer the greatest storage capacity, yet have the least characterized properties, particularly in regions that are not hydrocarbon provinces[5]. Hydrocarbon reservoirs offer the opportunity for revenue from enhanced oil recovery, proven sealing caprocks, data and infrastructure, which can combine to result in substantial cost and risk reduction[17,18]. However, complications in hydrocarbon reservoirs can be posed by the risk of leakage through legacy wells, differences in fluid properties between CO_2 and hydrocarbons, production history and pressure depletion, and upgrades required for using the existing infrastructure with CO_2 (refs. [19–21]).

Following from the geological requirements of a store, identification of suitable sites must focus on assessing containment, the capacity and injectivity[22,23]. Sealing caprocks for oil and gas have been dominated by two categories of sedimentary process: shales, formed during marine transgression, and evaporite deposits, originating either from sabkhas or evaporitic interior basins[24]. However, there are many exceptions, and fine-grained clastics and carbonates can serve as sealing layers. The key is that there are low permeability rock units that are both pervasive and ductile, such that their sealing qualities are endured throughout tectonic processes.

There are distinct geological requirements for CO_2 storage relative to oil and gas arising from the need for permanent containment. Long-term (>100 years) fault seal performance – whether pressure and fluids can move across faults bounding the side of a storage reservoir – can control storage integrity and plume migration, but it is difficult to measure using conventional workflows[25–27]. An industrial case study of the Troll field in the Horda Platform shows that a combination of geological information, data from analogue hydrocarbon fields and observations from wells can reduce the uncertainty levels acceptable for project progression[25]. In addition to the seal itself, the overlying rock layers, known collectively as the overburden, can substantially reduce the risk of escape of CO_2 to the surface. The proliferation of trapping processes with geological strata complicates and reduces the pathways available for CO_2 escape to the surface[20,28]. Because of the considerable risk reduction potential from the overburden, characterizing these layers is now considered as important for ensuring containment security as the reservoir and primary caprock[20,28].

Widespread storage will require a range of geological settings including locations that are not hydrocarbon-bearing and where geological data are sparse[29,30]. To date, CCS deployment has been restricted to locations known as extensional basins in which tectonic plates are stretching, characterized by low background seismicity. Site identification criteria have broadened with experience to include migration-assisted trapping as well as closed or semi-closed traps, increasing the number of potential site locations. For example, the storage sites for the Northern Lights and Quest Projects have no defined trap structure such as an arch-like anticline or a dome[31,32]. The Tubaen formation at Snøhvit is bound, or compartmentalized, by faults[33]. The Gorgon project makes use of water production wells for pressure management[34]. Thus building from experience in oil and gas, a new geology of CO_2 storage complexes is emerging and rapidly expanding the settings in which CO_2 storage can be deployed.

Reactive fluid dynamics, plume migration and trapping

The predictability of a CO_2 plume injected into the subsurface is important for permitting and site assurance through monitoring and verification of stored CO_2. Plume migration is driven by the pressure gradients between the target reservoir and surrounding formations, pressure gradients induced by injection, and buoyancy forces associated with the density difference between CO_2 and ambient brine (Fig. 1c)[35,36]. These interactions between viscous and buoyant forces, and reservoir and fluid properties, present both a challenge and an opportunity. Flows in the near well-bore environment can be influenced by injection strategies. Once CO_2 moves further, the path of migration is controlled by features of the rock and fluids – buoyancy, reservoir heterogeneity and the geometry of the stratigraphical trap.

The immobilization and trapping of CO_2 plumes are important for the long-term security of stored CO_2. For many scenarios, trapping of the CO_2 primarily occurs owing to a structural trap, as with the buoyant rise of CO_2 into a dome. Subsequent plume immobilization can be driven by the capillary trapping of CO_2, also called residual trapping, and through dissolution of CO_2 in groundwater[35,37]. Residual trapping occurs simultaneous with plume migration. The residual trapping of CO_2 can be greatly enhanced by heterogeneities that act to disperse the plume and provide barriers to buoyancy-driven flow[38,39]. At the largest scales, residual trapping can immobilize plume migration[40], a process which has been observed with modest injection volumes at the Otway test site in Australia[41].

Dissolution trapping can require decades or longer, depending on the extent of fluid convection in the reservoir[42]. The dissolution of CO_2 into water produces dense CO_2-saturated waters[43]. The increased density could lead to convection in highly permeable reservoirs[44] and enhanced dissolution rates in highly heterogeneous formations[45]. As with residual trapping, the dissolution of CO_2 can act to halt the advance of the CO_2 plume[46,47]. Substantial dissolution rates have been inferred at the field scale for magmatically derived CO_2[48]. Mineralization of the CO_2 can also serve as a trap. However, in sedimentary systems, there can be an insufficient supply of reactive minerals, and rates of chemical reactions are often sluggish, requiring millennia, and generally much longer timescales than in igneous rocks[4,14].

These trapping mechanisms act to immobilize the CO_2 plume and lower risks of leakage through pre-existing wells or fault systems[28,49,50]. The extent of risk reduction depends on the properties of the rock and leakage pathways (generally faults and wells) and the geometry of the storage complex. The more that reservoir heterogeneities can baffle flow away from leakage pathways, the more extensive the trapping. Sites can be identified in which leakage from the target reservoir would be largely or entirely halted before reaching the surface[51,52]. This mitigation potential underpins the evolution of site assessment from its initial focus on the target reservoir and caprock to its expanded emphasis on the storage complex as a whole.

The chief uncertainty in predictions for plume migration is the heterogeneity of subsurface reservoirs (Fig. 1c). It remains a marked challenge to characterize reservoir-scale heterogeneities at scales below the resolution of seismic imaging, which is typically a quarter of the seismic wavelength or 10–40 m for CO_2 storage applications. Centimetre-to-metre scale capillary and permeability heterogeneities can have substantial and varied impacts on flow and trapping. Flow parallel to layers will be enhanced, while also leading to more rapid dissolution. Carbon dioxide migrating upwards across layers can be baffled and slowed with enhanced residual trapping[8,53,54]. However, because these heterogeneities are difficult to characterize, they are a major source of uncertainty.

Important examples of exhaustively characterized CO_2 migration are the Sleipner and In Salah projects, with injection rates of roughly 1 Mt per year[55,56]. At the Sleipner project offshore Norway, the reservoir is permeable, and migration is dominated by buoyancy-driven spreading. The gravitational control on flow is particularly clear at the top of the reservoir where the topography of the bounding caprock, the Nordland Shale unit, dictates the evolving pattern of flow[57]. Carbon dioxide temperature and fluid composition also have a role in plume footprint and matching to observed data at Sleipner[58]. The buoyant flow at Sleipner contrasts with the In Salah project in which the project was halted owing to excessive reservoir pressurization. At In Salah, the reservoir was a thin (20-m thick) and low permeability fractured sandstone. As a result, injection pressures controlled the plume migration.

The deployment of projects in varied settings is driving our understanding of the physics of flow in gravity and viscous dominated systems, and the impacts of heterogeneity. Characterization and modelling approaches that can capture these key reservoir features and flow physics will increase predictive abilities in modelling, and lower risk in site development.

Managing induced seismicity

Although most earthquakes – and certainly the most damaging earthquakes – are of tectonic origin, earthquakes can be triggered by human activities[59–61]. Seismicity has been induced during fluid injection processes analogous to CO_2 storage including subsurface disposal of wastewater[62,63], conventional oil and gas production[64], gas injection[65,66], geothermal energy extraction[67] and groundwater pumping from shallow aquifers[68]. Owing to the similarities with large-scale geological wastewater disposal, the potential for subsurface CO_2 injection to induce seismicity, and approaches for managing and de-risking this outcome, has been an area of increasing interest for subsurface CO_2 storage[56,69–71].

Earthquakes occur when faults rupture, leading to runaway slip and the radiation of elastic waves[72]. The fundamental mechanism to induce fault slip – and, potentially, earthquakes – is a combination of two types of stress changes: an increase in shear stress on the fault and a reduction in compressive normal effective stress clamping the fault. The former can occur in bounding faults as a result of fluid withdrawal, as was the case in the Groningen gas field[73]. The latter occurs as a result of fluid injection leading to an increase in pore fluid pressure. Coupling between pressure diffusion and rock deformation results in changes in stress, known as poroelastic effects[74] (Fig. 1b). Poroelastic effects are often secondary, and they can have a role in triggering distant earthquakes[75]. Cumulative injected volume will impact the total pressure increase, which will affect the slip tendency on reservoir faults, especially in reservoirs that are compartmentalized or have low permeability[76,77].

The huge increase in seismicity in the mid-continent of the USA starting in 2009 is a cautionary tale on the potential effects of large-scale subsurface fluid injection[59,78]. A growing number of field observations suggest that fluid injection rates are also a determinant for induced earthquakes[79,80]. The injection rate effect has its underpinning in the frictional behaviour of faults under varying normal stress and can be explained from the onset of frictional instabilities[81–83]. These observations, demonstrating an increasing number of induced earthquakes during fluid extraction, led to policies and regulations that limit per-well injection rates, minimum permeabilities of the geological strata and maximum distances from faults[84], which resulted in a reversal of the trend. Site selection is therefore essential in limiting induced earthquake risks.

Although certain geological settings, such as those dominated by granitic rocks, would be prone to induced earthquakes and leakage risk that could compromise a CCS project[69,85], in the short-term, induced seismicity should not pose a barrier to CCS deployment. Many formations exhibit excellent promise for storing very large quantities of CO_2, especially in normally consolidated, shallow (< ~3 km) siliciclastic sequences (those characterized by alternating sand-dominated and clay-dominated sediments) in which ductile rocks can accommodate substantial deformation and faults behave aseismically[86,87]. Indeed, large volumes of buoyant fluids have remained stable in geological traps over millennia in regions experiencing strong and frequent earthquakes, such as Southern California, even under substantial overpressures[88]. Offshore sedimentary formations can have both high injectivity and storage capacity, making them viable geological storage reservoirs[89], and in some cases, these formations provide the only viable option, like in India.

A priori prediction of induced seismicity is challenging for a number of reasons[72]. The state of stress on a fault and the fault strength are heterogeneous and uncertain. The evolution of stresses on faults is coupled with fluid pressures and therefore depends on reservoir architecture and hydraulic properties such as porosity and permeability, which are also heterogeneous and uncertain. However, the frictional behaviour – seismic versus aseismic slip – depends on the lithology, offering an opportunity to select storage sites in which faults slip aseismically, minimizing the risk of induced seismicity.

In the absence of sufficient information to determine and mitigate the processes that trigger earthquakes, authorities have set up regulatory monitoring-based frameworks, known as traffic-light systems, with varying degrees of success[90]. These are intended to reduce the chance of induced earthquakes by specifying circumstances when injection should be halted or reduced. These frameworks are empirical and reactive.

There is broad consensus that more sophisticated approaches are needed[10]. Ideally, such methodologies should be built on comprehensive information about the subsurface to calibrate geomechanical and earthquake source physics models. These physics-constrained models should then be validated by comparing their predictions with subsequent observations made after calibration, allowing for forecasting and proactive management of reservoir operations to mitigate triggered seismicity[91]. Potentially, such approaches would also permit judicious placement of new injection wells and implementation of remedial measures (such as balancing injection or fluid withdrawal). We anticipate that this type of model-based management and mitigation could play an important role during the scale-up of CO_2 and H_2 geological storage.

Induced seismicity is thus not an immediate barrier to the scale-up of CO_2 deployment. Our understanding of its occurrence and its management is rapidly developing, anticipating issues that can arise with injection at much larger rates over the coming decades.

Lessons for underground H_2 storage

The commercial demonstration of CO_2 storage has increased confidence in the use of subsurface fluids in energy applications. Underground hydrogen storage (UHS) is one such technology envisioned to have a role in seasonal-based energy storage at the grid scale[92,93]. In this role, the storage will be cyclic, with H_2 gas temporarily stored to be later extracted to meet demands. Given that CO_2 storage is intended to be permanent, UHS is more similar to the use of underground natural gas storage (NGS) today (Fig. 2). The potential for subsurface H_2 storage reaches terawatt hours of energy content globally, far exceeding foreseeable demands[94]. However, the knowledge base and industrial experience are just beginning. Experience from CO_2 storage can be used to accelerate UHS technology development.

The geological host for hydrogen storage must meet some of the requirements for CO_2 storage: away from sensitive faults, sufficient capacity, good injectivity and a secure trap. However, there are many distinct important features. Carbon storage is for permanent sequestration, and hence open-ended complexes (without a caprock) that rely on residual and dissolution trapping can be used. As hydrogen is a commodity, purity and volume loss need to be minimized during storage and extraction, implying that structural traps are a requirement[95]. In addition, hydrogen-rich fluids have lower compressibility than CO_2 (ref. 96). As a result, unlike with CO_2, there is no sharp fluid density increase with depth (Fig. 2), and less incentive to target the depths deemed optimal for CO_2 storage.

Engineered salt caverns are well suited for hydrogen storage and have been in widespread use for NGS in the USA and UK since the 1960s[97], but they have drawbacks for large-scale deployment.

The availability of sufficiently thick salt deposits is geologically restrictive[92,98]. Because of the higher mass density of natural gas compared with H_2 in the subsurface (Fig. 2), approximately four times as much energy can be stored per unit volume for natural gas compared with hydrogen[96]. Available capacity can be expanded by injecting water into salt formations to engineer salt caverns for storage, but this incurs capital costs[99]. As a result, saline aquifers and depleted oil and gas reservoirs with caprocks have been identified as the most cost-effective H_2 subsurface storage option as they are ubiquitous and considered low risk[94,99,100].

There are also several distinct engineering aspects of H_2 storage relative to CO_2 storage. The seasonal cycling of UHS could place greater emphasis on the co-location of sites with hydrogen production to minimize cost and transport risk and on the streamline storage operations[101]. The intermittency of injection and withdrawal cycles on shorter time frames, compared with monotone storage of CO_2, raises additional challenges for well-bore integrity and rock plastic deformation under cyclic loading[102,103]. In addition, fault integrity could be a greater risk with increased cycling frequency and loads, as observed in petroleum applications[104]. As H_2 has low volumetric energy density and carries a high risk of steel pipeline embrittlement, it is poorly suited for long-distance pipeline transport or shipping[105]. Therefore, proximity will need to be weighed more heavily than for CO_2 storage in site selection criteria.

Hydrogen storage will cause various physically and chemically complex effects in the reservoir that are currently not well constrained. Understanding flow, containment and hysteresis of H_2 in rocks is not as advanced as CO_2 and presents a critical knowledge gap for H_2 storage[92,94,100]. Injectivity loss owing to salt precipitation is a well-studied phenomenon for CO_2 storage[106], whereas for UHS there is still uncertainty around analogous evaporative processes. Microorganisms in the subsurface can metabolize H_2, consuming it and producing unwanted contaminant gases such as H_2S in the process. The challenges of microbial conversion could limit underground storage to deep, high salinity formations to suppress microbial activity[107,108]. Increased understanding of the prevalence and impact of microbial conversion is needed to unlock the potential for re-use of depleted hydrocarbon fields and aquifers.

Understanding of the role of UHS during a sustainable energy transition is in its early stages and a key gap for future research. As with CO_2 storage, societal acceptance will depend on the perceived sustainability of the source and use of hydrogen[109–111], alongside local context and broader factors such as concerns over safety, trust in industry and social justice considerations[112,113].

Thus, although there are transferable learnings from CO_2 to hydrogen storage and these applications could be co-developed for industrial decarbonization, key differences between the physical properties of CO_2 and H_2 as well as site operation pose new constraints for UHS.

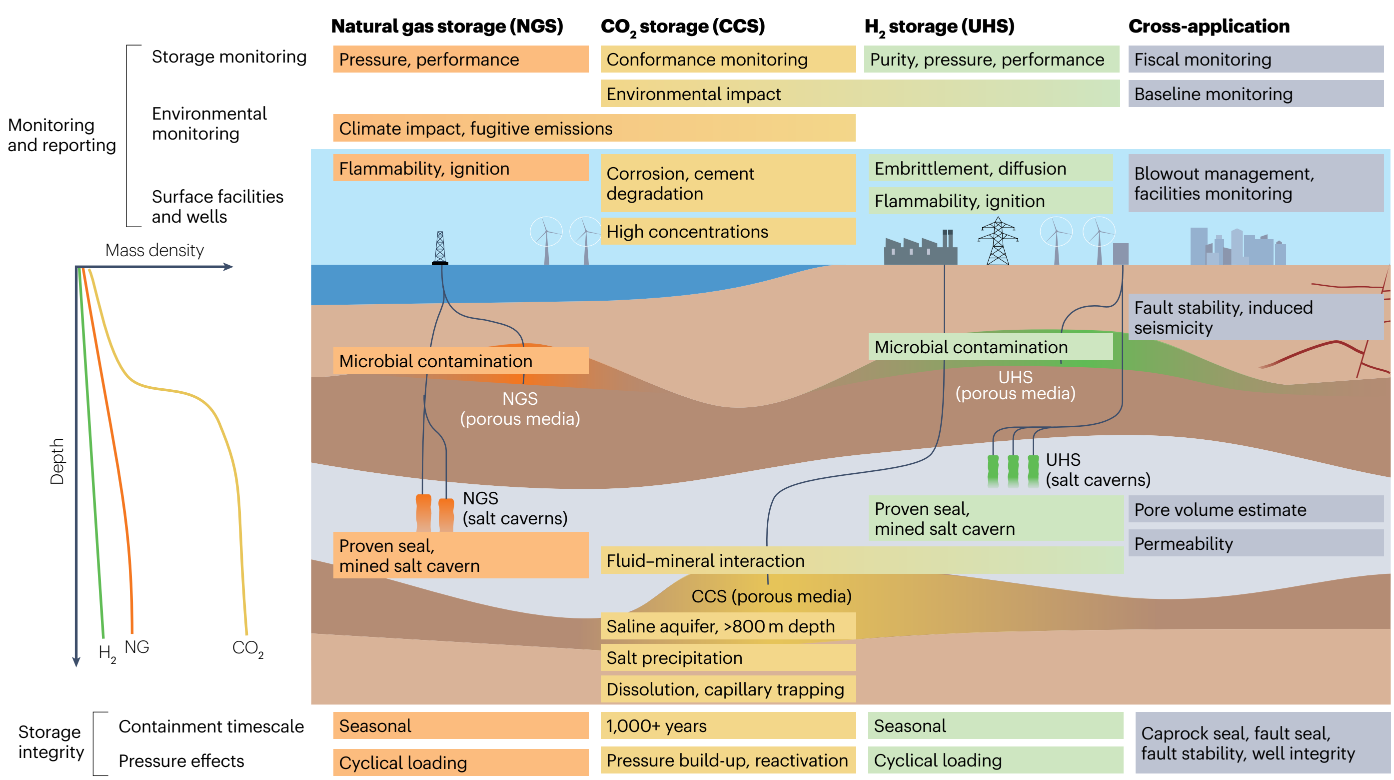

Fig. 2 | Comparison between the subsurface storage of natural gas, CO_2 and H_2. Diagram shows the different storage requirements for each of the three systems (natural gas storage (NGS) in orange, carbon capture and storage (CCS) in yellow, and underground hydrogen storage (UHS) in green) in terms of their surface facilities and infrastructure, monitoring and reporting, and storage performance and integrity. The grey boxes indicate the requirements applicable to all three systems. Notable differences include that NGS and UHS are designed as a seasonal-based storage facility, so that the stored resources can be trapped in times of high demand, whereas CCS is a long-term form of storage that needs to be contained for over 1,000 years. Similarities include the geological structures and permeability requirements, facilities monitoring and blowout management and the assessment of risks from fault instability and induced seismicity during injection.

In particular, hydrogen storage in porous media will be a central focus of research and development going forward.

CO_2 storage and sustainable development

Sustainable development has been a part of the discussion around CCS from its inception[114]. It has been used by the IPCC as an organizing framework for evaluating approaches to mitigating climate change[1]. A frequently used definition for sustainable development is Principle 3 of the 1992 Rio Declaration, which says: "The right to development must be fulfilled so as to equitably meet developmental and environmental needs of present and future generations" (ref. [115]). Assessment reports of the IPCC have linked technologies, including CCS, with their contribution to and detraction from the Sustainable Development Goals[1,116,117]. In this section, the contributions of CO_2 storage to sustainable development are evaluated through consideration of their impacts on environmental, economic and social issues.

Carbon capture and storage is frequently discussed as a transitionary technology towards a sustainable energy system[118]. The technological maturity of CCS components suggested potential for cost-effective, large-scale emissions reductions from coal-fired power production on a shorter time frame than alternatives and as a potential stepping stone to a hydrogen energy system[114,119–121]. In contrast to this transitionary framing, modelled development pathways synthesized by the IPCC suggest a long-term role for CO_2 storage in energy systems associated with power production, industrial processes and negative emissions chains[1]. In these scenarios, CCS scales up to mid-century and is then sustained or increased to 2100. Within these narratives, CCS contributes to sustainable development through its contributions towards climate change mitigation (environment) and the provision of a cost-effective low-carbon energy source (economic). Since 2010, the potential for CCS to facilitate employment opportunities in industrial regions has also been identified as a contribution towards a just transition (social)[122].

Environmental sustainability

Environmental sustainability is the purpose of subsurface CO_2 storage as a climate change mitigation technology. Lifecycle analysis has been extensively applied to various CCS chains and ongoing operations, demonstrating its efficacy and potential. These analyses underpin their representation in energy systems models and the resulting projections of gigatonne-scale deployment featured in the IPCC reports. The leading environmental impacts are associated with surface operations including the energy and chemical consumption of the CO_2 capture processes and the energy for the compression for transport. Energy consumption from subsurface operations, including field development, injection and monitoring, comprise 1% or less of the lifecycle costs[123,124]. However, two areas in which life-cycle emissions are sensitive to aspects of the subsurface are in the potential CO_2 escape, or leakage, from the subsurface store, and the use of CO_2 to produce oil in enhanced oil recovery processes.

The permanence of stored CO_2 is central to its effectiveness in emissions mitigation. There are no examples of CO_2 leaking to the atmosphere from existing industrial CO_2 storage sites. However, the issue receives major focus in project development where well integrity is the considered the leading risk of injected CO_2 escape[51,125]. The focus on well integrity as a potential source of CO_2 leakage follows from experience in the hydrocarbon industry in which gas escape from the subsurface through leaky wells is pervasive[126,127]. Over 30% of abandoned wells are considered to be potential leakage pathways in the risk analysis of industry projects[128].

The leading environmental concern of CO_2 leakage is the impact on climate change, although there could also be impacts on drinking water quality and offshore ecosystem health[52]. Because of the very large amounts of CO_2 storage envisioned in climate mitigation scenarios, up to 1,000 Gt CO_2 stored by 2100, models show that annual leakage rates of greater than 0.01% of stored CO_2 will negate the climate mitigation benefit of having stored the CO_2 (refs. [11,129,130]). Regulations require the remediation of leaking wells, and there is substantial industrial experience with repairs[131]. At the same time, there is a gap in identifying workflows for verifying storage integrity to the required level of precision, of <0.01% annually.

Another issue of environmental concern arises when CO_2 storage is used in combination with oil production (Fig. 3a). Most CO_2 storage today takes place in oil fields in which it is used to boost oil production, a process known as enhanced oil recovery. The revenues from oil production are so substantial, in the range \$40–110 per barrel (bbl^{-1}) from 2010 to 2020 (Fig. 3b), that economic models indicate enhanced oil recovery could be the dominant CO_2 storage configuration as CCS scales up to gigatonnes per year[17,132–134]. Life-cycle analysis of existing operations and envisioned scenarios with incentives for maximizing CO_2 use shows that for every 1 t of CO_2 stored underground, 1.5–3 t of CO_2 are emitted to the atmosphere, primarily from combustion of the end products of the produced oil[135–139].

The net climate benefit hinges on the extent to which the oil will add, or is additional to, total oil production in a market (Fig. 3a). If the oil production is additional, the emissions from combustion negate the benefit of the CO_2 storage. If instead the produced oil displaces production from other parts of the market, there will be no net increase in greenhouse gas from the oil. The quantification of additionality for CO_2 storage with enhanced oil recovery has seen little analysis. In an economic modelling study, the International Energy Agency found that as little as 20% of the oil in a global market could be additional, largely preserving the climate benefit of CO_2 storage when combined with enhanced oil recovery[132]. However, there are questions around how the climate benefit can be monitored at the market scale, and whether CO_2 storage through enhanced oil recovery will be supported by the public.

Societal acceptability

The widespread use of CO_2 storage will require broad societal engagement. Social impact assessment, community engagement and participation must be considered from project outset and tailored to the local context[140–144]. Indeed, as with other energy technologies, insufficient community support has contributed to the failure of attempts to implement CCS[145,146]. Furthermore, openness of technology, transparency of information and citizen participation are necessary to achieve broad acceptance for CCS[110].

Studying public perception is challenging for emerging technologies[142]. A prevailing feature of societal research in CCS is that there are low levels of public awareness[147–150]. Perception also varies with geography with increasingly negative opinions the closer a storage site is located, and whether the source of the CO_2 is domestic or imported[143,144,151]. There is evidence that benefit perception varies depending on the particular CCS chain[110,152,153].

Public attitudes towards CCS have been evaluated throughout Europe, in Canada, the USA, Brazil, Japan, China, Indonesia and Australia[147,154–158]. The leading predictor for the acceptance of CO_2 storage is how public perceive the benefits of the CCS technology chain relative to the risks[155,157]. Publics perceive that the leading benefits of CCS are its contribution to climate change mitigation. Job creation and

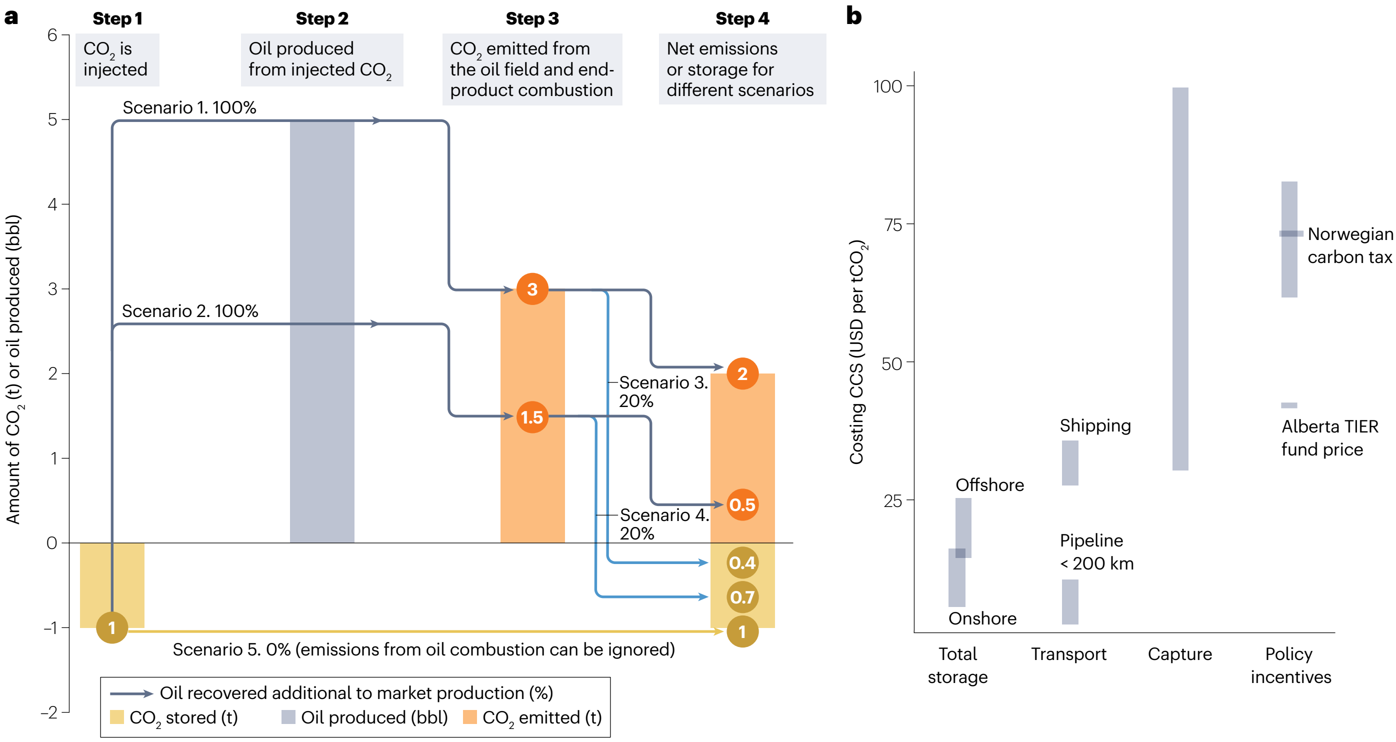

Fig. 3 | Carbon and economic accounting. a, Diagram showing considerations around the environmental benefit of CO_2 storage when associated with enhanced oil recovery. Following arrows from left to right shows five different enhanced oil recovery scenario examples based on 1 t of injected CO_2 (step 1). If that 1 t of injected CO_2 is used to produce 2.5–5 barrels of oil (bbl) through enhanced oil recovery (step 2), it would be associated with 1.5–3 t of CO_2 emissions from oil field and product combustion (step 3). If oil is 100% additional to market production (scenarios 1 and 2), then the net emissions would range from 0.5 to 2 tCO_2 (original emissions minus the 1 tCO_2 stored). If oil is only 20% additional (scenarios 3 and 4), then there is a net storage of 0.4–0.7 tCO_2. When 0% of the oil is additional to market production, the emissions from the oil can be ignored (scenario 5). **b**, Costs and potential revenues from components of the carbon capture and storage (CCS) chain and market policy support (Table 1). Enhanced oil recovery can provide a substantial revenue stream to overcome costs, but the environmental impact inclusive of the emissions from oil production is difficult to assess and monitor.

investment are also frequently cited in community surveys[157]. The leading risks perceived for CCS are associated with the subsurface[112], in particular, risks of CO_2 leaking to the atmosphere and associated industrial catastrophes, and the potential for induced earthquakes. People are also concerned about the long-term fate of CO_2 and storage site management challenges[159]. The gap between public perception of leakage risk and experts who consider the risks small suggests an opportunity for communication to improve public acceptance[156].

Public concerns around sustainability are also frequently captured in surveys. Issues raised include the character of CCS as an end-of-pipe solution, its association with the continued use of fossil fuels and its potential to divert financial and other resources from renewable energy development[155,160]. There is a perception that CCS does not address the root cause of CO_2 emissions and upholds the status quo of non-sustainable production[161,162]. There is also a lack of trust in industry and in the sincerity of efforts by corporations to transition towards a more sustainable future[163,164]. One opportunity to change this outlook lies with new narratives that position CO_2 storage as a component of carbon dioxide removal chains, addressing concerns about its role in CCS as an end-of-pipe solution[112,165].

Public perception of CCS will evolve further with deployment. Concerns might decrease with increasing experience or might increase according to how projects are perceived in terms of procedural and distributive fairness and tangible economic and wider benefits[166,167]. Social science research emphasizes the importance of understanding the local community context within which CCS developments sit. Project-specific measures to increase societal acceptance could include early and open engagement of stakeholders, provision of information and sources to support familiarity with CCS, understanding of community context and possible societal impacts, as well as tools such as community compensation. In short, societal acceptability of CCS will be place and application-specific, and depends on when, where, at what scale it might be implemented and trust in local industry and decision-makers[112,147].

Regulatory frameworks

There are mature legal frameworks enabling CO_2 storage at the international, national and substate levels in Europe, the USA, Canada and Australia (Table 1). These address issues from permitting and environmental assessments, to public consultation, tax credits and long-term liability[168,169]. These instruments set out requirements for site permitting including exploration and development; clarify ownership issues with respect to existing regulations around pore space and subsurface mineral rights; define requirements for successful operation and monitoring; and specify requirements for post-injection site stewardship and eventual closure. There are broad similarities among the enacted frameworks with some substantial variations in how pore space ownership is designated and the length of time required for stewardship of the site post-injection, from 15 years in Australia to 50 years in the USA.

As a brief example of what these regulations can encompass, we discuss the CCS Directive of the European Union (EU). The Directive has the objective of permanent storage, prohibits ocean storage, requires the permitting for exploration and storage, emphasizes careful site selection, risk assessment and monitoring and links with the trading scheme of the EU, the Emissions Trading Scheme. Monitoring injected CO_2 is linked to requirements of the Emissions Trading Scheme, such that liability for climate damage as a result of leakages requires surrender of emissions trading allowances for any leaked emissions. Furthermore, operators are required to provide financial security to provide for 30 years of monitoring. However, after closure of the storage site, liability transfers from the operator to the state (or 'competent authority' in the language of the Directive) after no less than 20 years. The transfer of responsibility takes place after a process known as history-matching whereby the monitored CO_2 is demonstrated to have behaved in a manner consistent with the ex ante computer simulations of the operator; there is no detectable leakage, and the CO_2 is moving towards long-term stabilization[170].

In several locations, and particularly Norway, Canada and the USA, these frameworks have created the certainty enabling the development of commercial CO_2 storage projects. As other nations around the world implement incentives to develop CO_2 storage, these succesful implementations can serve as a guide.

Technical feasibility of a future scale-up

The technology required for subsurface CO_2 storage at the single field scale is mature, including resource classification, appraisal, site development, operation and CO_2 plume monitoring. At the same time, these technologies are evolving as experience is gained, with an eye towards scale-up driven by expectations about the increasing role of subsurface storage in climate change mitigation plans.

Storage resource assessment

Estimates of the storage resource base have been a focus from the initial development of subsurface CO_2 storage. Resource assessments have been performed by government and research organizations for approximately 20 countries. Compilations of these data suggest that 10,000–30,000 Gt could be stored in suitable subsurface geology around the world[171,172] (Fig. 4). A maximum resource base of 2,700 Gt would be needed to achieve the largest scales of deployment illustrated by the IPCC, and the resource base should be sufficient even accounting for the considerable uncertainty in the geological estimates[2].

The United Nations Economic Commission for Europe and the Society of Petroleum Engineers Storage Resources Management System asset classification systems have been developed for storage resources[173,174]. A hierarchy of categories, such as from resources to

Table 1 | International legal instruments, regional regulations and policy-based market support for CO_2 storage

Jurisdiction or treaty body	Specific legal instrument or regulation	Policy-based market support
International organizations		
International Maritime Organization	London Protocol	NA
European Union and 15 countries	Convention for the Protection of the Marine Environment of the North-East Atlantic (1992)	NA
European Economic Area and the UK	European CCS Directive (Directive 2009/31/EC), transposed to domestic law	EU Emissions Trading Scheme
USA		
Federal	US Safe Drinking Water Act Underground Injection Control Program	45Q, a tax credit
North Dakota	ND Century Code Ch. 38–22 and ND Administrative Code 43-05	NA
Wyoming	WY Stat §35-11-313 (2019)	NA
Other	Several states have enacted laws and obtained legal primacy over the USDWA for enhanced oil recovery and extended those laws to regulate CO_2 storage with enhanced oil recovery	California Low Carbon Fuel Standard
Canada		
Federal	Primary authority with individual provinces	NA
Alberta	Carbon Capture and Storage Statutes Amendments Act 2010 Technology Innovation and Emissions Reduction Regulation (TIER)	TIER fund price
Australia		
Australia	Offshore Petroleum and Greenhouse Gas Storage Act (2006); National Greenhouse and Energy Reporting Act (2007)	NA
Victoria	Greenhouse Gas Geological Sequestration Act 2008; Offshore Petroleum and Greenhouse Gas Storage Act 2010	NA
Queensland	Greenhouse Gas Storage Act 2009	NA
Western Australia	Barrow Island Act 2003	NA
South Australia	Petroleum and Geothermal Energy Act 2000	NA

NA, not applicable; CCS, carbon capture and storage; EC, European Commission; EU, European Union.

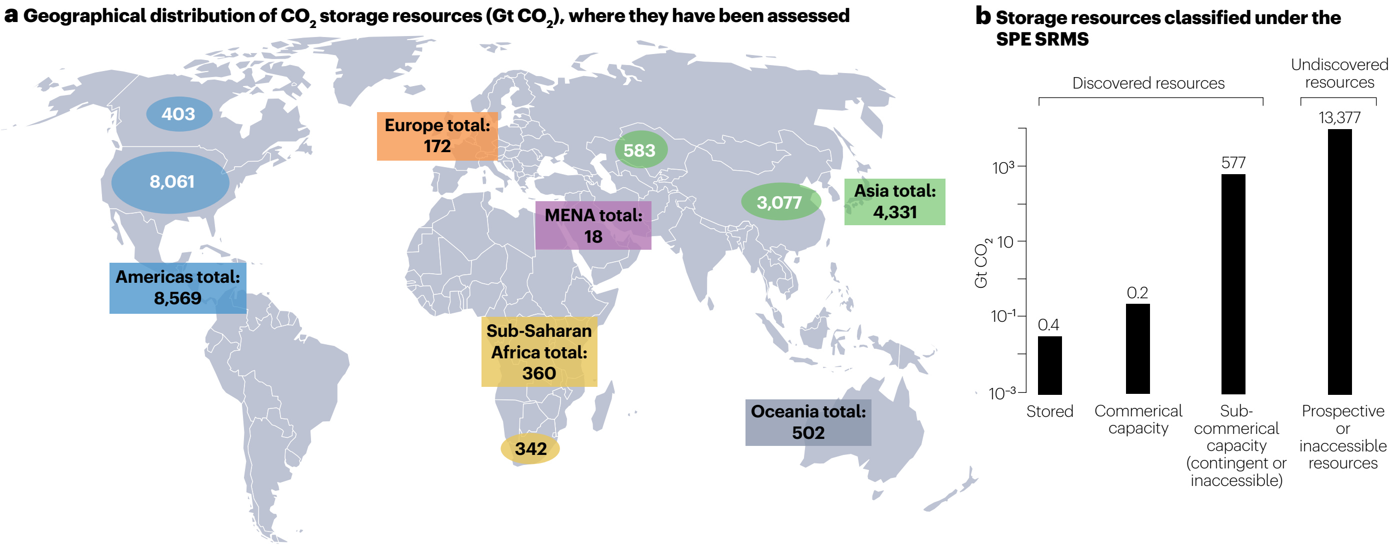

Fig. 4 | Global storage resources by geography and resource classification. **a**, A map of the combined storage resources by country or territory (circles) and region (boxes) where they have been assessed[172]. Note that assessments have not been performed for many locations around the world so that these numbers are not comprehensive. **b**, Black bars on a logarithmic axis show the global estimates for resources under the classification categories of the Society of Petroleum Engineers Storage Resources Management System (SPE SRMS)[172]. There are abundant resources potentially available relative to the amounts that will ultimately be matured to commercial categories. MENA, Middle East and North Africa.

capacity, is driven by the state of commercial feasibility (Fig. 4). These systems emphasize near-term commerciality, significant for the declaration of assets on company balance sheets. The highest level of classification is achieved only with imminent or ongoing project investment and operation. An evaluation of global storage resources found that approximately 96% would classify as an 'undiscovered resource' in the Storage Resources Management System[173,174] and is indicative of locations where the geology is understood, but no reservoir characterization activity such as the drilling of wells has taken place. A further 4% is classified as 'sub-commercial' resource[173,174], in which the reservoir has been characterized, but there is no viable business proposition. Much less than 1% of the resource has been developed to the commercial status where storage operations are imminent or active, which is termed 'capacity'[173,174].

Site development and engineering

Industry best practice for maturing storage resources from prospective to commercial has developed with project experience[5,18,175–178]. The Storage Readiness Level is a framework developed to track the degree of maturation for specific sites[179]. The process follows established workflows from the oil and gas industry and includes site screening, selection and characterization[180]. Typically, the process will take 2–4 years.

Monitoring the CO_2 injection gives operators assurance that the project is in conformance, reduces uncertainties existing at the outset of the operation and addresses societal concerns[176,181]. Monitoring plans need to balance cost-efficiency and value of information[182]. Geophysical techniques are indirect methods to interrogate the storage reservoir and to monitor plume migration. Time-lapse seismic imaging is the most important geophysical technique for CO_2, but gravimetric and electromagnetic methods and distributed fibre optic sensing have also been developed[183–185]. The observed plume can be used to confirm or update model predictions[186]. Downhole pressure and temperature measurements at the injection well are used to monitor injectivity and to detect leakage into overlying aquifers. Notably, there are no commercial techniques for observing residual or dissolution trapping, which is currently addressed through simulation-based history-matching[187,188].

Risk management is central to the planning and operational phases of CO_2 storage projects[189]. In practice, the risk of unsustainable injection rates is the largest risk to a commercial project[190–192]. Site engineers have several tools and resources available to address risk, ranging from models and simulation, data acquisition to geophysical monitoring. Storage projects expect a risk profile that decreases steadily during site planning, operation and closure[193] (Fig. 5). If anomalies are observed, such as gas detected at the ground surface or sea floor, or unexpectedly rapid plume migration, a new evaluation of risks will determine whether an operational change is needed[194–196].

With increasing demand for storage, individual site development will need to be put in the context of a portfolio of storage sites (Fig. 5a). A portfolio of sites can be connected by a common aquifer and a pipeline or shipping-based distribution network[197]. Managing multiple sites simultaneously comes with additional challenges. Pressure communication and interference between sites can substantially impact the risk of injectivity and capacity loss at individual sites[198,199]. There could be need for regional-scale pressure management, and the aggregate risk profile could be qualitatively different from that for individual sites[200–202] (Fig. 5b). Regional management will require forecasting pressure over space and time over scales well beyond that of any given site[9,203]. Uncertainty, data scarcity and lack of acceptable regional-scale models make modelling over regional spatial scales challenging[204].

Business models for carbon storage

Project costs and revenues are central to the deployment or failure of CCS chains. Minimizing costs associated with capture by obtaining CO_2 from high-purity sources, generating revenue from the sale of CO_2

for use in enhanced oil recovery and minimizing total project size are currently leading factors in project progression[7,205,206].

The subsurface component of costs is well established for projects with capture and injection rates in the range 0.5–5 Mt CO_2 per year and injection lasting between 10 and 30 years. Detailed cost models, regional storage cost supply curves and Front End Engineering Design studies covering a range of storage environments are publicly available[128,178,207–212]. Over the life of a storage project, costs in 2020 ranged from USD \$5 to \$15 per tCO_2 stored for storage onshore and from USD \$15 to \$25 per tCO_2 when storage was offshore (Fig. 3b). The leading cost components include site characterization, the construction of wells and site monitoring pre-injection and post-injection, primarily seismic imaging. To place storage costs in context, capture costs associated with power production range from \$30 to \$100 per tCO_2 and pipeline transport costs range \$1 to \$5 per tCO_2 for every 100-km distance[207,208]. As a result, storage costs comprise 10–20% of the total CCS chain when CO_2 is captured from dilute flue gas streams, whereas they can dominate full chain costs when CO_2 is obtained from a high-purity source such as natural gas processing or when capture rates are below 500,000 tCO_2 per year[210,213].

Costs are recovered through a combination of government grants, policy support in the form of tax credits or avoided tax (Table 1), revenue from the sale of carbon credits or the sale of CO_2 for enhanced oil recovery[214–216]. When CO_2 is captured from low-purity streams such as flue gas from power production, government-supported capital grants have been required[214]. When CO_2 comes from high-purity streams such as natural gas processing or ethanol production, there are a number of demonstrated business models. In Norway, the Sleipner and Snøhvit projects are economic because the costs of storage are less than the cost of a tax imposed on CO_2 emissions[211]. A number of storage projects in the USA have succeeded entirely from revenue from the sale of CO_2 for enhanced oil recovery, around \$30 per tCO_2, and can obtain tax breaks of twice this amount through the 45Q policy[214] (Table 1). In Alberta, Canada, the Quest Project obtains substantial revenue through the generation and sale of carbon credits under the Technology Innovation and Emission Reduction regulation[32].

Business models are now emerging to overcome the barriers of costly infrastructure and expensive CO_2 capture from dilute emissions streams. The Norwegian government financed the Longship Project with capture and storage of 800,000 tCO_2 per year. The Northern Lights Joint Venture was awarded the role of the CO_2 transport and storage operator[217]. There is extra-injection capacity, up to 1.5 Mt per year, and the Northern Lights project could sell this capacity to other carbon capture operators. The UK government, similarly, is establishing a private transport and storage operator that will own an initial pipeline and storage infrastructure[218]. Although initial capture projects will be government-financed, the storage operator will subsequently generate revenue through a user-pays model in which industries contract for the offtake of their CO_2 emissions.

Scale-up to climate relevant injection

There are 26 commercial CO_2 storage sites operating around the world, each with injection rates between 0.5 and 2 Mt CO_2 per year[219]. These projects have a CO_2 capture capacity of around 40 Mt per year and as of 2019 were storing at least 29 Mt per year underground[6] (Fig. 6). At least 197 Mt CO_2 has been stored underground since 1996[6].

These projects operate in a range of settings. Sleipner, the first dedicated CO_2 storage site, and Snøhvit are offshore and associated with natural gas production[5,55,177,186]. The In Salah, Quest and Decatur projects are all onshore projects with storage in saline aquifers[5,175,177,220]. The remainder of projects are onshore with CO_2 injection into oil fields, with concurrent enhanced oil recovery.

Projects comprising over 100 Mt per year capture capacity have been announced in some stage of development, with injection planned

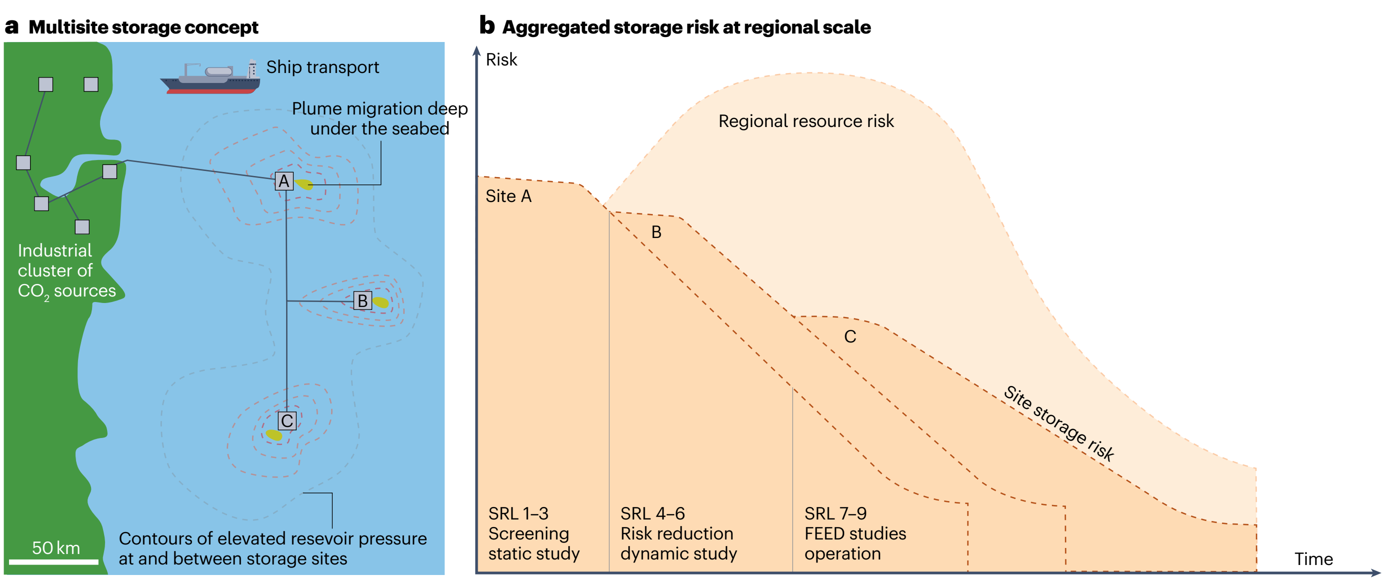

Fig. 5 | Risk reduction strategies for multiple offshore underground storage sites. a, An example of an offshore multistore development with CO_2 derived from an onshore industrial cluster. Storage sites A, B and C are sequentially developed. **b**, Schematic example risk profiles for the individual sites A, B and C (shown in part **a**) and regional resource risk in aggregate as Storage Readiness Level (SRL) progresses. Knowledge gained from the development of earlier sites serves to de-risk subsequent development of other sites in a region. The aggregate risk profile is qualitatively different from that of single sites. FEED, Front End Engineering Design.

to begin before 2030[219,221]. A number of the proposed projects in the North Sea are designed around systems which allow access to multiple suppliers of CO_2. These projects include the Aramis and Porthos projects offshore the Netherlands and the Northern Lights Project offshore Norway. Business models involving static consortia include the Hynet (UK), Northern Endurance (UK) and Green Sands (Denmark) projects. Injection wells for CO_2 storage comprising between 15 and 30 Mtpa were permitted in 2021 in the USA, indicative of the impact of policy support[222]. Reviews of past development and industrial experience with energy projects in general suggest that only up to around 20% of these projects will develop to the point of injection taking place[7,206,212]. The number of projects in development has been increasing since a low point in 2017[219].

Projections of future demand for CO_2 storage are found in both techno-economic studies evaluating climate change mitigation and government roadmaps for achieving greenhouse gas emission reductions. For mitigation achieving less than 2 °C of warming, global storage rates need to scale up rapidly to on average 5–10 Gt of CO_2 injection per year by 2050. These rates are sustained, resulting in 350–1,200 Gt of CO_2 stored underground by 2100[1,114,223]. The UK Government has identified mitigation trajectories with scale-up of CO_2 storage to 75–175 Mt per year by 2050. The EU and the US Governments have identified trajectories with 2050 storage rates ranging from 80 to 300 Mt per year and 1 Gt CO_2 per year, respectively, by 2050[224,225]. Although the number of projects in development is increasing, and individual country targets are ambitious, they will still fall far short of CO_2 storage deployment in trajectories synthesized in mitigation scenarios incorporated by the IPCC[219] (Fig. 6).

A number of analyses suggest that it is not the geology or engineering limiting this scale-up. Well construction for oil and gas in the Gulf of Mexico and North Sea has achieved analogous rates of development sustained over decades starting in the 1950s[89,226]. Wastewater injection into deep sedimentary formations in the USA reached approximately 1.2 Gt in 2012[14,227]. Regional-scale and global-scale analysis suggests that pressure limitations will be limited to a few locations[36,198,226,228]. Source–sink matching suggests that the global distribution of suitable geology will facilitate regionally disperse use of CCS[229].

Industrial growth at rates matching trajectories in the IPCC Assessment Reports are historically unprecedented for an infrastructure-intensive energy technology[2] (Fig. 6). Analysis of regional variation in historical oil production shows that fluid injection and extraction in China and India have never approached the volumes modelled for CO_2 storage in integrated assessment models, indicative of a more limited capacity for scale-up in these regions[226]. At the same time, the infeasibility of matching IPCC trajectories to 2050 should neither diminish the plausibility of achieving climate change targets as a whole, nor undermine confidence in the performance of CCS as a large-scale climate change mitigation technology[6,7]. Maintaining existing growth, while falling far short of trajectories by 2050, would lead to cumulative storage amounts by 2100 commensurate with 1.5 °C mitigation pathways[1,2]. The mismatch in trajectories produced by integrated assessment models and models developed from considerations of aspects of subsurface storage shows the importance of constraining mitigation scenarios with respect to the growth of CO_2 storage. Appropriate constraints in integrated assessment models will avoid the creation of scenarios with implausibly high scale-up to 2050[2,230]. Generating more realistic scenarios could be achieved by combining any number of simplified models representative of subsurface geological[198], geographical[229] and techno-economic[2] constraints with integrated assessment models.

Carbon storage underground is a technology that has achieved industrial scales of deployment and has great potential, not unduly limited by geology, geography or engineering for achieving climate-relevant scales of CO_2 mitigation. Scale-up will almost certainly not achieve the storage rates projected in 2050 or earlier for most of the scenarios synthesized in the IPCC Assessment Reports. However, the difference in projected and plausible scale-up mostly highlights a gap caused by the lack of constraints from the subsurface in scenario modelling and is not a strong indicator of shortcomings of CCS or the plausibility of meeting climate change targets as a whole.

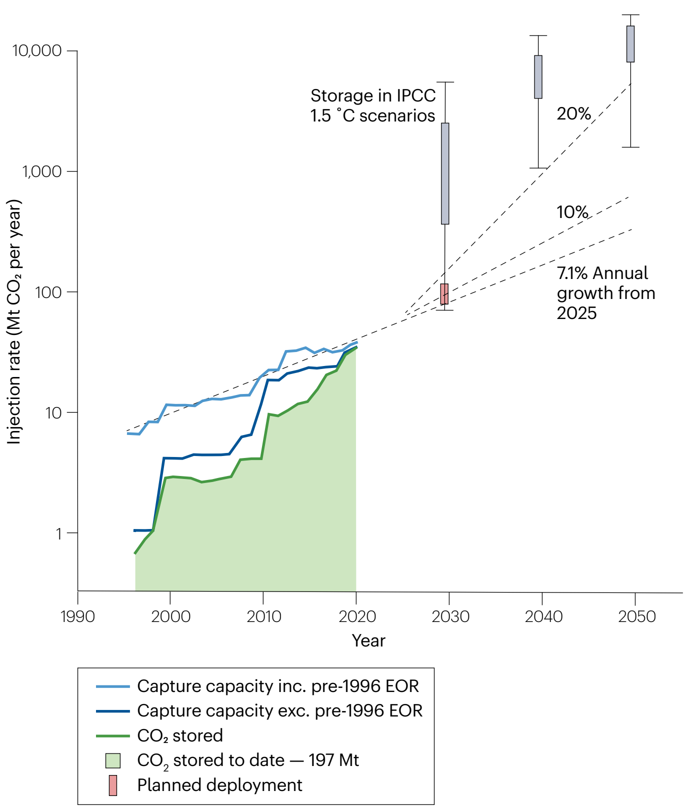

Fig. 6 | Current deployment, project pipeline, exponential growth trajectories and storage rates in the 1.5 °C Intergovernmental Panel on Climate Change scenario. The CO_2 capture and storage capacity from 1996 to 2020, including[205] or excluding[6] enhanced oil recovery (EOR) projects operating before 1996, are shown in light and dark solid blue, respectively. Green line and shading show estimates of actual CO_2 stored, approximately 20% less than the capture capacity[6]. Three annual growth projections at 7.1%, 10% and 20% from 2025 are shown. The box and whisker plots indicate the CO_2 injection rates required to meet the 1.5 °C warming scenario of the Intergovernmental Panel on Climate Change (IPCC). In summary, 20% annual growth in carbon capture capacity from 2025 could fall short of the lower estimates of CO_2 storage required by 2040, and most estimates for 2050, to limit anthropogenic warming to 1.5 °C.

Summary and future perspectives

Subsurface carbon storage is deployed today at industrial scales with storage rates in 2019 of at least 29 Mt per year across 26 projects. The geological settings of deployment are varied, including saline aquifers, oil fields and geological complexes that rely on structural or residual trapping for plume immobilization. Plume migration, induced seismicity and CO_2 leakage to the surface do not pose immediate challenges, with rapid advances in their prediction and management taking place. Hydrogen storage underground has emerged as a prospect for terawatt-scale energy storage and can benefit from a range of geophysical similarities to both subsurface CO_2 and natural gas storage. Achieving locally tailored public acceptance is essential for project success with leading public concerns including CO_2 leakage and seismicity, and a continued dependence on, and legitimization of fossil-fuel technologies. Legal certainty derived from regulation, such as the EU CCS Directive, and policies enabling viable business models through tax or carbon credits are also enablers of project deployment. Subsurface carbon storage is on track to play a major part in future climate change mitigation.

At the same time, there are many uncertainties that arise from the scale of envisioned CO_2 storage required to limit anthropogenic warming to 1.5 °C. At gigatonne scales, resource use expands well beyond the consideration of single sites to entire basins. New modelling tools will be required to characterize multisite storage resources and to optimize resource development and management at regional scales. Leakage rates must be kept to on average <0.01% annually, and systems similar to nationwide emissions monitoring programmes must be developed for quantifying storage across large numbers of sites. An evolution is underway in managing seismic risk, moving from the reactive traffic-light system towards a more sophisticated approach analogous to history-matching in plume management. The progress in understanding the reactive fluid dynamics of subsurface CO_2 offers the promise of accurate predictive and history-matched modelling of plume behaviour. These advances will need to be built into commercial reservoir modelling and simulation software to enable their incorporation into industry workflows. These advances would enable substantial reductions in risk and cost during the operation of sites.

Subsurface hydrogen storage is comparatively less studied. Experience with CO_2 storage can guide approaches for efficient resolution of unknowns around the fluid flow properties, the impacts of cycling on store integrity and the management of microbial degradation of stored H_2. Many fundamental questions can be answered through immediate laboratory-based measurements. Because of the similarity to natural gas storage, and the benefit of H_2 as a commodity, it is possible that industrial-scale H_2 storage will scale up rapidly compared with the growth of CCS. The main enabler will be the demand for the use of H_2 as an energy carrier.

The tax and carbon credit incentives in the USA, Canada and Norway demonstrate that viable business models for CO_2 storage can be developed from market-based policy support. The proliferation of projects in the USA in response to the strengthening of the 45Q tax policy, in particular, supports this approach to incentivization. The development of more expensive project chains, capturing from dilute sources of CO_2 or transport through shipping, will be an important test of the impact of policies that now provide revenue streams >$60 per tCO_2. The existing success of these policies should be considered as indicators of the magnitude and type of support that lead to successful deployment, particularly for governments with ambitions for CO_2 storage scale-up, such as the UK, EU, Australia and China. Given the extent of policy and financial support probably required, major efforts must be made to increase both public awareness and societal acceptability. Techno-economic modelling shows that CO_2 storage with enhanced oil recovery can be a contributor to climate change mitigation, but quantifying the aggregate environmental benefit and achieving societal acceptability remain major uncertainties that should be addressed in the short-term.

The variety of geological, regulatory, social and policy environments in which CO_2 storage is deployed and under development today demonstrates a robustness of the technology as a climate change mitigation tool. When progress in development is measured against reasonable benchmarks such as the historical growth of the oil and gas industry or the climate mitigation impact relative to renewables, its current strength of position is revealed. Integrated assessment models require updates to present plausible growth trajectories for this technology. However, the technical, regulatory, social and economic tools are known and in place to continue development to gigatonne scales of mitigation.

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Additional information
Correspondence should be addressed to Samuel Krevor.

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[1]Department of Earth Science and Engineering, Imperial College London, London, UK. [2]Technology, Innovation and Society Group, Department of Industrial Engineering and Innovation Sciences, Eindhoven University of Technology, Eindhoven, The Netherlands. [3]Department of Environmental Science, Radboud Institute for Biological and Environmental Sciences, Radboud University, Nijmegen, The Netherlands. [4]Energy Department, Technology Division, NORCE Norwegian Research Centre, Bergen, Norway. [5]School of Law, University of Edinburgh, Edinburgh, UK. [6]Institute for Management Research, Radboud University, Nijmegen, The Netherlands. [7]Department of Geoscience and Engineering, Delft University of Technology, Delft, The Netherlands. [8]Department of Civil and Environmental Engineering, Massachusetts Institute of Technology, Cambridge, MA, USA. [9]Department of Earth, Atmospheric and Planetary Sciences, Massachusetts Institute of Technology, Cambridge, MA, USA. [10]Centre for Environmental and Industrial Flows, Department of Earth Sciences, University of Cambridge, Cambridge, UK. [11]Department of Applied Mathematics and Theoretical Physics, University of Cambridge, Cambridge, UK. [12]Department of Civil and Environmental Engineering, University of Strathclyde, Glasgow, Scotland.