Developing a Robust Commercial Demonstration and Deployment Track Record for Geologic Sequestration

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Abstract

The investability of carbon capture with geologic sequestration benefits from the long and substantive record of success in the subsurface injection portion of the value chain. Success can be defined as meeting three tests: 1) injection of the planned amount of CO_2 at the planned rate for the planned duration; 2) demonstration that the CO_2 is retained permanently in the storage complex with sufficient confidence so that financial incentive is earned, and 3) avoidance of unacceptable outcomes that could result in liability, penalty, loss of social license or regulatory permission to complete the project.

Investor confidence that this technical success can be achieved for CO_2 storage is based on 1) understanding the contributions of the relevant multiphase porous media fluid flow physics to attaining secure storage, 2) evaluation of the significant and growing US and global experience with CO_2 storage, 3) evaluation of success rates for many decades and 1000's of sites where analogous injection and storage operations including waste water disposal, natural gas storage, and injection of CO_2 for Enhanced Oil Recovery (EOR). Investability is increased by physics of retention of CO_2 in the subsurface, the quality of the research on geologic storage, and the extensive track record for diverse types of injection that is indicative of success.

Information and experience available now are sufficient to assure success of large and sustained CO_2 storage projects, however this information is not widely available. Beneficial next steps include 1) making more readily available the outcomes from past permitted injections and 2) testing programs to probe and optimize factors that cause investor concern, such as well management, fractures and faults, and induced seismicity. In addition to building from existing experience, ensuring experience with CO_2 storage is reported in a transparent and accessible manner to investors and developers is crucial.

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1. Demonstrating a Track Record for Geologic Sequestration that Supports Investability of CCUS Projects

Technical success for a storage project that underpins financial success is defined by three parameters: 1) injection of the planned amount of CO_2 at the planned rate for the planned duration; 2) demonstration with sufficient confidence that the CO_2 is retained permanently in the storage complex such that financial reward metrics can be met, and 3) avoidance unacceptable outcomes that could result in 3a) liability or other penalty or 3b) loss of social license or 3c) loss of regulatory permission to complete the project. Unacceptable outcomes include damage to fresh water, impact at surface, damage to other resources (e.g., hydrocarbon production), subsurface trespass, and unacceptable magnitude and frequency of seismicity.

Storage of CO_2 in the deep subsurface as part of an integrated capture and storage project targeted to reducing emissions in order to achieve climate goals has been accomplished dozens of times globally and so far for limited durations with limited volumes; these successes are described in the second section and shown on Figure 1. Because this experience record is weak and localized, anxiety is high about project components, including the storage process itself, the reliability of the project development process to be repeated as many times as needed for large scale CCS deployment, each project's ability to sustain large volume offtake for long time periods, and closing a project to end financial responsibility for it. Developing a new technology in new geographic settings raises conventional first-of-a-kind barriers. In this chapter we review how past knowledge and deep experience with fluid injection in the subsurface can reduce barriers by showing that injection of CO_2 to prevent accumulation in the atmosphere is a continuation of a long-standing experience with successful and regulated large volume injection.

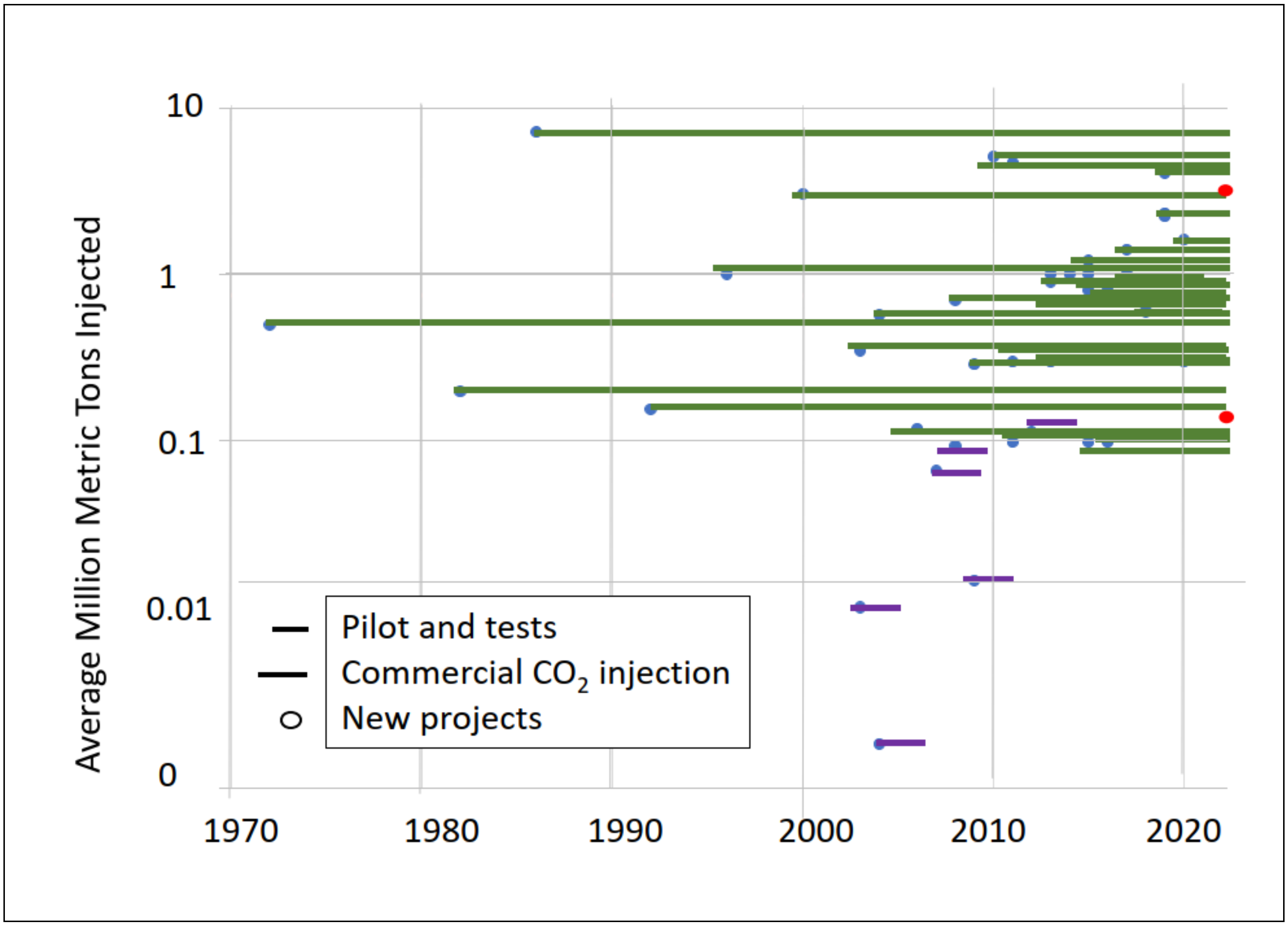

Figure 1. Survey of 41 Project CO_2 injection amounts and durations

Geologic settings generate a different uncertainty portfolio than engineered facilities. With this difference comes concern from project developers who are more accustomed to the highly engineered and controlled constructed environment. Geologic storage takes advantage of the scale (1-4 km deep, 10's to 100's of km2 in area) and the fabric (sand and clay size grains stacked in repeating layers over the entire space). No engineered feature could provide a facility this robust for accepting and retaining fluids. However, the complexity and scale also mean that aspects of the response are difficult to predict with high certainty. As an analogue, even the best technology and know-how can result in drilling "dry holes" that fail to produce hydrocarbons. Communication of risks and certainties in the subsurface to a wide group of investors, owners, residents, regulators and others is needed so that confidence is attained.

In this chapter we review reasons for confidence that technical success in storage will be attained using 1) first principles of relevant physics, 2) US and global experience with CO_2 storage, 3) analogues from other related injection and storage such as wastewater, gas, and injection of CO_2 for Enhanced Oil Recovery (EOR).

1.1 Physics of Storage as a Source of Confidence

The mechanisms considered here are specific to porous media storage in sedimentary rocks such as sandstone and limestones. CO_2 storage can be considered in other types of rocks, for example basalts, where mineral trapping is the major storage mechanism, or in naturally or artificially fractured material such as coal, lignite, or shale. However, these rock types and storage mechanisms are excluded from this discussion specifically because the first principles that give storage confidence in porous sedimentary rocks are not present in these settings.

Sedimentary rocks are composed of granular materials separated by pore spaces on the 0.001 to 10 mm scale. Flow processes through porous media are dominated by the interaction of the pores and the smaller pore throats that connect them. The parameter of a porous material that relates flow rate to applied pressure is permeability. Rocks with large and well-connected pores are described as highly permeable and serve as injection zones for fluids. Rocks with small and poorly connected pores are described as “confining zones”. Flow in rock with small, poorly connected pores is slow and requires high pressure drops so that fluid migration is essentially stopped.

Flow is also a function of the fluid properties. Most pores in the subsurface are filled with water. At depth (0.5-4 km) this water is highly saline with dissolved salt concentrations several times seawater and is known as brine. When storage is classified as “saline”, brine is the fluid that is displaced by CO_2. CO_2 phase behavior is complex under the relevant pressure and temperature conditions. In typical subsurface environments at depths greater than 750-800 m, supercritical conditions are achieved and CO_2 density is in the range of 0.6-0.7 g/cc; this phase is denser than the gas phase so that storage is efficient. Supercritical CO_2 is less dense than brine, so that when possible CO_2 will ‘float” on top of brine; that is, it will migrate upward. In addition, as it migrates upward it becomes less compressed and therefore less dense and buoyant forces increase. CO_2 also has lower viscosity than brine, so that it is more mobile. Low density and high mobility are the reasons why leakage of CO_2 from the subsurface and escape to surface waters or the atmosphere are of concern and care is required in selection and operation of the storage facility.

However, when porous media contain two immiscible phases, the pore structure of the rock becomes very important in retaining fluids. In most rocks, brine is the wetting phase, indicating that occupies the pore space near the grains. CO_2 is the non-wetting phase; it forms “bubbles” in the brine (Figure 2b). The surface tension of the contact between CO_2 and brine is effective in trapping the bubbles and restricting them from entering or leaving the pore throats (figure 2c). Therefore, rocks with small pore throats cannot be entered by CO_2 “bubbles” at reasonable pressures; these barriers to multiphase flow are called capillary seals. In more permeable rocks, capillary forces are also important in limiting flow. As CO_2 enters each pore and displaces brine, the pressure required to move CO_2 though the rock decreases non-linearly with increasing saturation until a maximum CO_2 saturation is reached. Capillary-bound “irreducible” water is retained in the pores. If the input of CO_2 is stopped, for example at the end of injection, the CO_2 will continue to migrate as far as it can under buoyant forces. However, saturation of CO_2 will drop and capillary effects will limit the ability of CO_2 to move out each pore; bubbles of CO_2 will be “snapped off” and left behind as immobilized residual saturation (figure 2c). The percent of immobilized residual CO_2 varies based on rock properties; in flow zones 15% to 60% residual saturation is typical. Summing retention of CO_2 as residual across a flow system made of many pores results in attenuation of the mass available to migrate. This means that at the end of injection the CO_2 plume that was moving through a rock volumes under driving force or buoyancy will spread out, reducing the saturation toward residual, and the movement of the plume will stall. If a plume migrates, it will stabilize as it reaches conditions where none of it can be extracted. Residual trapping mechanisms work in concert with other trapping mechanisms including structural trapping beneath confining systems as well as in smaller structures at the reservoir architecture, bedform and pore scale and by dissolution of CO_2 into brine. In some rocks trapping via precipitation of a mineral phase may be significant also.

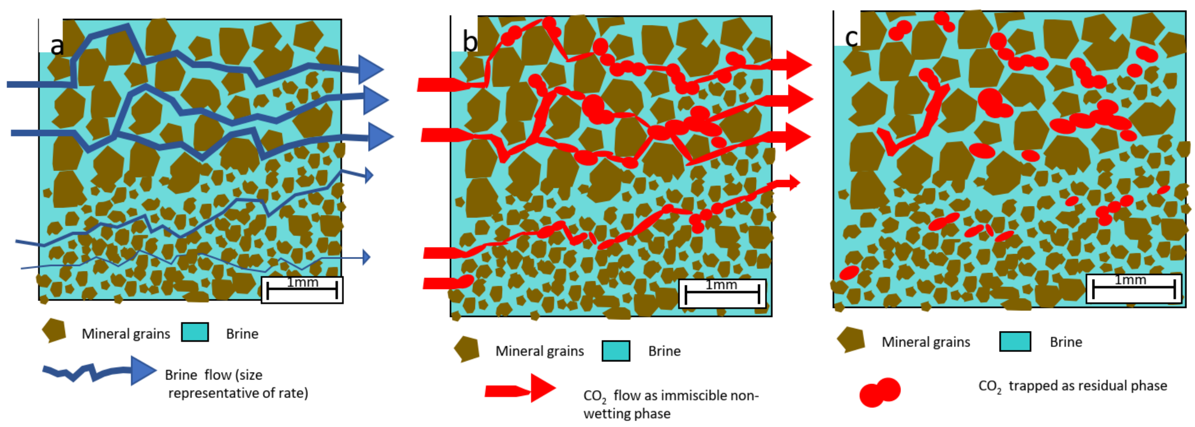

Figure 2. Illustrations of the flow properties of granular sedimentary rocks

Figure 2 illustrates the flow properties of granular sedimentary rocks: a) single phase flow conditions illustrating the factors that control fluid migration: pressure drop, fluid properties, and the size, shape and connectivity of spaces between grains. Small spaces between grains in the lower part of the image result in minimal flow, such low permeability rocks are described as confining; b) image of multiphase flow of CO_2 into brine-saturated rock illustrating interaction of CO_2 in pores because of capillary forces, and c) "snap off" trapping of bubbles of CO_2 in hysteretic (incompletely reversable) saturation.

Residual saturation as a mechanism for stopping migration is very well known. Essentially every hydrocarbon reservoir undergoes this process. At early stages, hydrocarbon saturation is high and oil or gas can be moved quickly to wells. This is the phase of primary production where the buoyant column of hydrocarbon may flow to the surface without pumping. As saturation and reservoir pressure is diminished by production, the hydrocarbon becomes more difficult to move and more force has to be applied by pumping to lift it to surface. Water becomes more easily mobile, increasing "water cut". Eventually the energy required to produce the hydrocarbon drops below the value of the produced hydrocarbon and the field, which still contains 10-60% of the original hydrocarbon in place, is depleted in terms of economically recoverable fluids. The same forces will immobilize CO_2 in the injection zone at the end of injection but there will be no production phase where CO_2 is pumped out. Upscaled field experiments that show the CO_2 plume migration stalling have been conducted several times in cases where injection stopped and monitoring continued, for example Frio test, Nagaoka test, Otway Stage 2B, Otway Stage 3 test, results in preparation.[a,1,2,3,4,5,6,7,8]

1.1.1 Inventory of flaws and limits of the retention assurance of sedimentary rocks

Limitations on effective capillary trapping occur when the cross section (aperture) of connected or elongated pores become large. The main features that are large enough so that flow is not limited by capillarity are wells and fractures.

1.1.1.1 Wells as potential flaws to retention

Wells are designed to be as effective as possible in transmitting fluids from depth to surface and vice versa, so control of flow in them is essential. Well controls include various types of tube-in-tube arrangements and the connectors between the tubes. For example, at depth the large diameter casing and tubing within it are separated by packers that isolate the well casing from flow, so the tubing functions as a double barrier flow path. The wellhead allows the operator to access the well casing or the tubing at the surface. During well drilling this equipment has not been installed and an array of management tools known as blowout preventers is deployed. During well reentry for “workover” other systems are installed. Most major and many minor accidental and consequential leakage are well control failures.[9,10,11,12]

Loss of well control can be catastrophic; for example the Macondo blowout and explosion, the Aliso Canyon well.[13,14] However, these well-control failures resulted from operational and regulators not following and enforcing well-known best practices rather than new or unexpected failure mechanisms. Note that models of substitution of CO_2 for hydrocarbons in these events results in less severe impacts because of the properties of CO_2.[15] Intervention to regain well control after a CO_2 blowout has been accomplished multiple times (e.g. Lynch

a Experimental validation of capillary entry pressure and residual saturation is widely done for hydrocarbons. Experiments with CO2 to derive these values are available, however experiments are somewhat technically difficult to accomplish therefore the data relevant to specific rocks systems are limited. The supercritical phase of CO2 at reservoir temperature and pressure complicates the laboratory conditions. CO2 solubility in water is low but varies with temperature and pressure and must be held at saturation over the entire experiment to avoid conflating dissolution and residual trapping effects. In addition, it is important to create flow conditions that mimic those in the injection zone and allow capillary forces to be separated from viscus flow. This requires long core pieces and long experimental times.

et al. 1985 describing a blowout at natural CO_2 dome accumulation).[16] One method to further reduce well-related risk for a developing CCS industry would be to curate common methods for management and mitigation of well containment issues.

In addition, wells are a well-known liability at the end of use. If wells are not managed, they can degrade and convey fluids either downward or upward to contaminate resources at the surface or groundwater. For this reason, most areas with wells have rigorous programs to force well owners to stabilize them prior to abandonment via a specified well plugging program. In addition, if no responsible party can be found, orphan well programs are instituted to perform the proper plugging and abandonment (P&A). Plugging programs vary depending on jurisdiction, however they consistently include filling the well casing with intervals of heavy drilling muds and balanced cement plugs at key intervals and cutting the well-off below grade. Records are produced that provide assurance that this program has been effectively conducted. However, failure to enforce plugging practices for both owned and orphaned wells and failure to complete sufficient records are widely problematic for many reuse applications, including geologic storage. Prior to obtaining an injection permit, the operator will conduct a survey of all wells and individually evaluate the sufficiency of the P&A records, with critical review by the regulator. Wells for which evidence of proper P&A is insufficient must be reentered and plugged.

Several variants of non-isolation of wells are noted as having special significance to geologic storage. When wells are drilled, they are required to be constructed to isolate water resources from the deep subsurface and as well as the active hydrocarbon producing zone or the fluid injection zone from the overlaying inactive zones. This is generally achieved by pumping cement down the casing, out a cement shoe at the bottom of the well, and exerting enough pressure to force cement back up on the outside of the well casing against the rock wall of the borehole. This is done at least twice, once to isolate the fresh water prior to drilling into non-potable brine-bearing units, and once at the production interval. However, failure to isolate is possible, for example, if cement picks up rock and drilling mud impurities and fails to create a strong barrier to flow, or the casing is poorly centered, and cement doesn’t completely encircle the casing. If not enough cement is pumped to fill the casing-borehole anulus upper zones may not have cement squeezed to fill the spaces over the intended interval. Another issue may be that the interval isolated for production is different from the interval intended for storage, resulting in lack of cement at the storage interval. Well cement evaluation is an important part of permitting a site.

1.1.1.2 Fractures as a risk to retention

Fractures also may have aperture which can be large enough to transmit multi-phase fluids quickly. Fractures in a zone that is made of fine-grained materials may make the zone fail to confine brine or CO_2, resulting in failure to completely store all the CO_2. Fracture aperture is typically elliptical, meaning that one individual fracture is open in the middle but closes and disappears with distance from the center. Therefore, for fractures to transmit fluids long distances, they must form an interconnected fracture network. For example, fracture sets on one diagonal can intersect fracture sets on the other diagonal and create open pathways. Fracture aperture is responsive to state of stress in the host rock, therefor it is unlikely that they will all be open, as the stress will close some of them, however, injection can change the state of stress sufficiently that fracture sets will be opened. Such fracture opening was observed in a closely monitored CO_2 injection project in Algeria known as In Salah (for example, Rinaldi et al., 2019).[17] CO_2 was inadvertently injected for a period at pressure high enough to open known fracture sets in the lower part of the fined-grained confining system. The pressure was then increased in the confining unit, and the resulting subtle uplift of the land surface was imaged using satellite-based Interferometric Synthetic Aperture Radar (INSAR). Indicators of fracture opening also included microseismic signal, but no felt seismicity. The fracture systems apparently did not propagate through the upper part of the thick fine-grained interval and no CO_2 loss to aquifer or atmosphere was detected. Fracture opening pressure is relatively easily measured during operations and can be avoided. If the fractures begin to open in the subsurface, the injection rate increases or injection pressure decreases, which should quickly signal the operator to reduce injection rates and lower reservoir pressure to allow fractures to close.

1.1.1.3 Faults and Seismicity

Faults and seismicity are often cited as concerns in providing potential escape routes for CO_2. However it is important to correctly understand these issues in assessment of storage security risk. Faults are formed where long-term continued differential stress exceeds the strength of the rock, a fracture system forms, and continued differential stress incrementally moves the rocks on one side of the break past the other. Fractures can be man-made, but faults require recurrence of motion for many thousand years. Energy released during the movement of rocks against each other creates waves which are referred to as seismicity that propagate through the rock mass. The earthquake energy released during fault motion is a complex response to many factors, however, is generally proportional to the size of the area of fault that slips. Therefor in general, large (long, deep and high offset) faults are higher risk of producing unacceptable ground motion than small faults.[18] Most unacceptable induced seismicity has been at faults that were either known or could have been known.[19,20] Seismicity is not an immediate trigger for stopping injection as shown by Cogdell EOR field, where numerous seismic events attributed to water and CO_2 injection have been measured.[21] However, brine and CO_2 injection continues, although the operator reports that some adjustments in the injection patterns were made to decrease seismicity. Fault slip generally does not open pathways to the surface, however changes in stress may open some fractures allowing unintended migration. Damage to rock grains including breakage (catalysis) or “smear” of weak grains as well as precipitation of minerals can impede fluid flow along or across the fault. Faults that are not detected during storage site selection and description can be problematic in creating unexpected flow. In many cases the fault forms an unanticipated barrier to flow, however enhancement of flow in unacceptable ways is also possible. Analysis of rock volume response to changes in injection rate (e.g. injection fall-off test) can be used to diagnose unexpected barriers as well as fast paths. Seismic risk is important to consider but tools are available to assess it during project siting and mitigate if it should occur.

1.1.1.4 Saturated Column Height as a Risk to Retention

Another limitation on the effectiveness of residual saturation occurs when CO_2 accumulation is focused in a “trap”. A trap is formed where the flow paths for fluids converge, forming, in effect, an upside-down bowl which fills with migrating buoyant fluids. Commercially extractable hydrocarbon has accumulated in and is producible from such traps. Where CO_2 injection project selects a trap setting for injection, the saturation of CO_2 will increase over time as CO_2 displaces water and migrates to accumulate a thick column at the crest of the trap. If a transmissive feature (fracture system or unplugged well) accesses the trap, flow may occur and be sustained though it unless mitigated. Pressure depletion and decreased saturation will retard the rate of flow though such a crestal failure, however fluids migrating from deeper may replenish the saturated system and allow leakage to continue. Long term seepage via such pathways is known. Examples illuminate rates and impacts of such seepage: a damaged hydrocarbon well offshore Louisiana known as Taylor Energy spill; natural fracture systems that to seep in offshore California, or a shallow gas storage facility placed near the crest of a faulted structure near the German village of Knoblauch leaked so that the village had to be moved to avoid risk to the population.[22,23,24] The trade-off between the reduced location uncertainty of storage in a trap has to be balanced with longer term maintenance of mobile CO_2 columns. This is another example of tools that can be used to manage storage risk.

1.2 U.S. and Global Experience with CO_2 Storage: The Existing Track Record

Although exact prototypes of the future storage projects are sparse, practical experience applicable to building confidence in large-scale commercial geologic sequestration is abundant. In the following sections, this experience is reviewed starting with the saline storage pilots, tests, and commercial projects and continuing to control releases (experimental storage failure simulations), and analogues for storage including waste injection, CO_2 injection for enhanced oil recovery (EOR), and gas storage.

1.2.1 Saline storage experience and demonstration of maturity

Experience with CO_2 injection with monitoring and oversight to attain storage value has now been accomplished in 20 locations. Both R&D and fully commercial projects are reviewed in this section and summarized in table 1. Some of the inventory has been active over decades and data made available in the public domain; new projects just commencing are also listed.

Numerous small and short duration storage field tests have been conducted globally. Results from these tests have been too commonly discounted as providers of experience because they were not linked to anthropogenic capture, were conducted using research and development (R&D) funds outside of a commercial model or were permitted outside of mature commercial procedures. However, because these test were conducted in R&D mode, the data density is unusually high, the test beds are diverse, the entire life cycle from initiation to closure and abandonment has been completed, and results published extensively in peer-reviewed and publicly accessible literature. The results of these pre-commercial test programs were designed to prepare for commercial storage and should be received as effective in providing confidence in storage itself, modeling and validating models with monitoring, testing and improving best practices, and probing of the limits of information that can inform the current phase of commercialization. Some of R&D tests were conducted with CO_2 from various sources, including extracted from subsurface accumulations prior to reinjection, however the subsurface behavior of CO_2 is similar irrespective of source and impurities. For example the Otway test has significant methane in the injection stream from a natural accumulation and this composition is input into models, however results seem entirely generalizable to pure CO_2 injections.

Table 1: Examples of R&D Oriented Tests and Commercial Projects Focused on Injection into Saline Formations with Monitoring to Document Retention

Short name	Location	Main contributions	Citation
Sleipner*	Norwegian North Sea	First CCS project, still continuing, large scale, commercial, permitted, and extensively modeled and monitored.	Furre et al, 2017[25]
Snøhvit*	Norwegian Barents Sea	Early, still continuing, solved pressure management, 4-D seismic	Eiken et al, 2011[26]
Nagaoka	Japan	Detailed high frequency logging to image free and dissolved CO_2. Achieved closure	Sato, et al, 2010;[27] Mito, et al. 2011[28]
Frio Pilot	Dayton, TX	Highly monitored, history-matched model and measured plume, geochemical and tracer data, novel acoustic methods, achieved closure	Hovorka, 2013[29]
Mountaineer	West Virginia	injection into relatively thin zones, achieved closure	Mc Neil et al., 2014[30]
Citronelle	Alabama	Highly monitored early integrated project, achieved closure	Koperna et al, 2012[31]
Ketzin	Germany	Highly modeled and monitored many participants, achieved closure	Martens, Sonja et al, 2014[32]
Cranfield (saline)	Cranfield, Mississippi	"Stacked storage" test downdip from EOR, extensive modeling, electrical methods and process-based soil gas	Hovorka et al. 2013[33]

Otway	Victoria, Australia	Multi-staged multizone test site, pioneered and developed monitoring and modeling techniques, recently fiber deployments, recently completed	Paterson, 2013[34]
Michigan	Gaylord Michigan	Above injection anomaly detected.	Battelle Memorial Insitute, 2011[35]
Decatur*	Decatur Illinois	Phased intensely monitored injection, transition from research to commercial, continuing at site. Two permitted wells from different projects at this site, one active, the other monitoring	Couëslan, et al, 2014; McDonald 2017[36,37]
In Salah*	Algeria	Closely monitored saline injection in the down dip part of a large gas field. geomechanical response to overpressure injection was documented, no serious impact. Project suspended.	Eiken et al, 2011[38]
Tomakomai	Hokkaido, Japan	Closely monitored injection, continued injection after damaging earthquake in nearby area. Injection into volcaniclastic rocks. In post-injection phase	Japan CCS Co, accessed 2022[39]
Gorgon*	Australia	Large continuing injection, novel water extraction to manage pressure. Sparse public information. Active.	Government of Western Australia Department of Mines, Industry Regulation and Safety, accessed 2022[40] Carbon Neutral Coalition, 2022
Aquistore	Alberta, Canada	Experimental monitoring laboratory, intermittent injection, active	PTRC, accessed 2022[41]
Quest*	Alberta, Canada	Commercial storage, intensive published “bow tie” risk management monitoring showing methods for decrease over time, active.	Bourne et al., 2014[42]
Shute Creek *	La Barge, Wyoming	MRV plan – acid gas	U.S. Environmental Protection Agency, 2019[43]
Red Hills Gas Processing Plant*	Jan, Lea County, New Mexico	MRV plan – acid gas	U.S. Environmental Protection Agency, 2021[44]

Tundra SGS LLC*	Grand Forks North Dakota	Class VI, North Dakota primacy, new permit	U.S. Environmental Protection Agency, 2022a[45]
Red Trail Energy, LLC*	Richardson North Dakota	Class VI, North Dakota primacy, new permit	U.S. Environmental Protection Agency, 2022b[46]
Net Zero Teeside*	UK	New project	NET Zero Teeside accessed 2022[47]

** Indicates a sustained large scale or commercial project. Additional permit applications are listed by U.S. Environmental Protection Agency and by state agencies (accessed 2022).*

These intensely studied CO_2 injections into saline formations provide high confidence in the quality of geologic characterization into fluid flow models to predict CO_2 plume and pressure evolution, Monitoring provides validation of the robustness of modeling, prediction, and ability to bring projects to closure. A number of smaller less widely published tests were also conducted out of the US regional partnerships program, as well as in Europe and Asia. In addition several saline injection projects have been conducted in China, however detailed data are not widely available for these results.[48]

Although this inventory of injections provides validation of the robustness of characterization, modeling and monitoring, it is worth considering the ways these initial experiences are imperfect analogues to commercial saline projects of the future. The first limitation is scale in terms of maximizing injection rate per well, drilling multiple wells per project, and sustaining injection for many decades. None of the projects listed in Table 1 are scaled to accept all of the regional emissions, or even all of the emissions from a large power plant. Predictive modeling to upscale very large deployments has some uncertainties in the nature of pressure increase over regions. Uncertainties involve the effective distribution of pore-pressure increase over complexly connected flow units. For example, the elevated pressure observed in the lower Mount Simon injection zone at the Decatur project was focused in the lower part of the units, with minor sedimentary layers focusing flow in this zone.[49] The implication of partial use of the potential flow units can be higher pressure elevation and a larger energized pressure area in the preferred zone. This means that another injection zone could be placed in the upper Mt. Simon and have minimal injection interference as was done with the second project well. However, it is unclear how this will scale up to larger areas and longer times. Similarly, zones at the top, bottom and margins of the flow unit can be involved in accepting pressure over time, resulting in decreased pressure elevation in the main flow zone. This effect was observed in Michigan Pinnacle reefs, which are hydrologically closed compartments. However, post injection pressure was observed to decline, which is interpreted as a result of fluid slowly accessing less active part of the reef, and reducing pressure (not leaking).[50]

Many of the table injections have been somewhat tied to oil and gas activities. Otway, Frio, Citronelle, Nagaoka and Cranfield for example were designed to lower cost by partial leveraging or reuse of adjacent or associated hydrocarbon production. Hydrocarbon and associated fluid extraction is an aggressive pressure relief mechanism and has to be considered as a main element of the project boundary conditions. However, Decatur, Tomakomai, Mountaineer, Quest and Aquistore are far from any hydrocarbon activities. A step-out from dense production related data has both negatives (less data) and positives (fewer preexisting penetrations). No breakdown of understanding is observed in comparing projects from hydrocarbon regions to those from non-hydrocarbon regions.

A number of projects advanced to test-well drilling but did not advance to development. Projects advancing to well testing build confidence that large volume storage opportunities are widely seen as available and commercially viable. In no case was the reason for project suspension failure of the storage concept. The Future Gen Site in Mattoon, Il was the most advanced of these in that it gained a permit before government suspension of funding.[51] The UK's offshore Goldeneye project attained an advanced stage of readiness prior to injection.[52] Other pre injection advanced projects include the draft permit for Tenaska's Taylorville.[53]

Pre-injection characterization, test data, and permitting information are being generated for numerous wells drilled recently as part of the permit preparation activities under the US DOE Carbon SAFE program.[54] Multiple new projects are in planning in the North Sea including planned injection into the UK sector and the Norwegian sector.[55,56,57] Similar well test stage projects are underway in Victoria, Australia. Global project lists are available from the Global CCS Institute and from IEA.[58,59] For the US, U.S. Environmental Protection Agency (EPA) is posting Class VI permits as they complete stages of review.[60]

1.2.2 Controlled Release Tests

A different category of tests is reported to bound the outcomes of CO_2 injection. Current projects have not leaked CO_2 to shallow zones, groundwater, or the surface. A series of tests have been designed and conducted to test groundwater, soil, ecosystem, ocean and atmosphere response to leakage as well as to test and optimize monitoring, detection and leakage assessment. An inventory representative of these "controlled release" experiments is shown in Table 2. Leakage impacts are generally subtle but can be detected if the right tools are placed close enough to the leakage point. In general, controlled release results discourage an assumption that broadcast episodic project-wide surveillance is highly effective in assuring no leakage. The highest benefit of monitoring seems to be when changes in ecosystems are observed they can quickly be attributed to leakage or to non-project changes.

Table 2: Inventory Representation of "Controlled Release" Experiments

Short name	Location	Main contributions	Citation
ZERT	Montana	First controlled shallow soil release, test many approaches – water, soil and atmosphere	Spangler et al., 2010[61]
Cranfield	Mississippi	Aquifer controlled release, tools for optimizing analytes, sampling methods	Yang et al. 2013[62]
Balcones Field lab	Austin TA	Aquifer controlled release, tools for optimizing analytes, sampling methods, Remote monitoring	Yang et al.2014[63]
ASGARD	UK	Ecosystem tests, minimal damage to crop	Smith et al. 2013[64]
EIT	Korea	Soil gas detection experiment	Jun et al. 2017[65]
Ressacada	Brazil	Soil gas detection experiment	Oliva et al. 2014[66]
Ginnendara	Australia	Soil gas, very localized signals	Berko and Fietz, 2012[67]
Norwegian field lab	Norway	Aquifer and sediments, geophysics and geochemistry, complex interactions	Eliasson et al.2018[68]
CAMI		Controlled release at intermediate subsurface depths, optimizing geophysical and other detection.	University of Calgary, accessed 2022[69]
Northwest Hub	Australia	Fault-related small injection with leakage	Michael et al., 2020[70]

QICS	Scotland	First shallow offshore controlled release	Plymouth Marine Laboratory, accessed 2022[71]
STEMM CCS	UK North Sea	Intensively monitored controlled release with multiple detection approaches in water column.	STEMM CCS, accessed 2022[72]

1.3 Using analogues from other related injection and storage to establish technology maturity

CO_2 injection for geologic storage is not unique but is part of a cluster of well-developed technologies which individually and via their intersections provide high levels of existing confidence, operational experience, and insight into relevant risk profiles of injection activities. Linked activities include large volume sustained waste fluid injection for disposal, large volume sustained CO_2 injection for enhanced oil recovery, and natural gas storage; each is discussed below.

1.3.1 Wastewater Disposal in Deep Wells

The US and Canada have major advantages compared to parts of the world that do not have large volume wastewater disposal in the subsurface. In the US and Canada CO_2 injection permitting program has been built quickly and with high confidence as a follow-on to the existing portfolio of activities, in terms of best practices, risk management, and permitting. Subsurface wastewater injection became widespread as a preferred way of disposing of brines produced in association with hydrocarbons early in hydrocarbon development because of the obvious damage resulting from surface releases of these saline brines, as well as because returning brines to the reservoir interval can maintain reservoir pressure and help recover more hydrocarbons (secondary recovery). This existing technology was incorporated as part of the US Safe Drinking water Act (SDWA) of 1974, which limited discharge of industrial waste fluids, and set US-wide standards for deep well injection of wastes from all sources as part of the Environmental Protection Agency (EPA) Underground Injection Well Control (UIC) program.[73] Similar programs are deployed in other countries, but we do not attempt to review them in this paper.

Although the success of the UIC program in terms of sustained large volume injection at many locations with few incidents has been excellent, the program results are not very well known to investors, likely because the records that document this experience are found in diverse locations within the distributed permitting system. Wells that dispose of fluids intended for disposal of pre-refinery waste generated during hydrocarbon production as well as wells that are designed to improve extraction were already widely in operation at the time of the promulgation of the SDWA. These ongoing activities, therefore, were grouped US wide as UIC class II, given a nonprescriptive charge within the SDWA to protect USDW, and the state agencies that were already managing these activities granted "primacy" to continue management. Class II covers disposal of oil field brine, injection of brine for pressure support, injection of CO_2 for EOR, injection of "acid gas" CO_2 and H2S stripped from hydrocarbons to reach purities required for pipeline transport, and any other injectates intended to increase production (e.g. "frack fluids"). Records of these activities are therefore kept by state oil and gas regulators in states where they exist and reporting is in some cases modest and not standardized. The new category of injection developed under the SDWA for facility wastes, Class I, has a detailed permitting requirement, including intensive site characterization, injection zone and confining system specification and pre-injection well testing.[74] Class I requires modeling of an Area of Review (AOR) where injection will cause elevated pressure such that an open flow path connecting the injection zone with surface can allow fluid to migrate into USDW and mitigation of all possible flow paths in the AOR. Class I has a specified program of monitoring both the injection well and the overlying USDW during injection. This program was distributed by allowing states to qualify for primacy, some states accepted and either conducted the Class I program with Class II or assigned it to another agency or division. For states that did not obtain primacy, the Class I program is generally administered by regional EPA offices. In addition, when the hazardous waste laws of RCRA and CRCLA were added to EPA's program, an amendment to the UIC program was required for waste streams that include constituents listed as hazardous under those laws. Such injection wells are managed by EPA regions under "no migration petitions" which grant disposal exemptions. The result of this distribution of authority is that the records documenting more than 40 years of operation of the UIC program require visits to many locations.

In 2010, EPA promulgated a new rule establishing Class VI specifically for injection for permanent storage of CO_2. CO_2 EOR under class II is exempted. The new rule is built on Class I, however includes new elements requiring enhancements such as plume tracking, multiphase modeling and verification via modeling, and formal closure procedures. States are applying for primacy to administer the class VI program (at the time of writing North Dakota and Wyoming have obtained primacy, Louisiana is in process, and a number of other states have stated or implemented intention to apply).

We note that digitizing and making more available past UIC experience in many jurisdictions would likely benefit the existing UIC program as well as the new use of the program for CCS.

The class II program has permitted injection of very large volumes of brine. A recent analysis of the injected rates and per well volumes are analogous to those needed for large scale CCS increases confidence in injectivity in high quality saline formations of the Gulf Coast.[75] Records of Class II failure to retain are rare, in part because the risks have been minor and readily remediated and in part because systematic monitoring to detect any unacceptable events or reporting is not done. Inventories of well failure can be found in state archives, for example the Railroad Commission, which regulators oil and gas activities in Texas, records “blowouts” on a searchable data base and partial reviews of the experience with these state programs prepared.[76,77,78,79]

1.3.2 Seismicity from Class II Injection

Injection for brine disposal has also induced unacceptable felt seismicity in some regions, which has been widely publicized and raises a warning for CO_2 injection as well as all deep well injection. A number of reviews and projects have been initiated to assess this concern and develop management strategies in the context of CCS.[80,81,82] A complete review of induced seismicity is out of scope for this review, however some highlights of the state of knowledge are overviewed. It is important to separate deliberately induced fracturing of the subsurface as part of permeability enhancement for hydrocarbon release from triggering of events which are larger than the energy input (that is a release of potential energy). The terminology is used variably in different reports because deliberate and accidental fracturing are end members of the same physics. The state of stress in the subsurface allows formation of fractures; if low stress definitely exists, the fracture size and energy released will be proportional to the energy input. An example of this type of deliberately fracturing a well in a low permeability rock (unconventional hydrocarbon resource) is described: A slug of water is forced into a segment of perforated well, deliberately breaking the rock or opening existing partings or fractures. This is followed promptly by a slug of proppant that is intended to hold the fracture aperture open, so that after the well is pumped hydrocarbons can use it to flow from the rock to the well. Fracture opening creates seismic waves which can be measured to image the process. These deliberate events created by water injection are proportional to the energy stored in the rock; most commonly they are small and cannot be felt at the surface. Temporally associated with deliberate fracturing for development of unconventional resources is large volume disposal of produced water. Rapid increase of subsurface pressure has resulted in occurrence of multiple unintended seismic events, some of which have been felt and which are considered unacceptable.

The subsurface state of stress is incompletely known. Stress is commonly high in deep zones and less in shallow zones, or differently orientated with depth or across a region.[83] However, it is relatively straightforward to measure at a site by inducing a small fracture in an open hole or perforated well; this is known as a mini-frac or diagnostic fracture injection test (DFIT).[84] Testing to failure can provide assurance that injection below the triggering threshold can proceed. However caution may still be needed because of the possibility of the area of elevated pressure encountering a region of the subsurface with different stress state.

Many large areas have low differential stress; the rate of strain created by forces in the earth is lower than the rate of relaxation of the rocks, so stress is not built up. This is especially true in high porosity high permeability rocks desirable for CO_2 storage. Monitoring of seismicity is rarely deployed in such low differential stress areas. For example a high quality 3-D array was installed at the Cranfield project by RITE, in a project designed wanted to gain experience at a large volume CO_2 injection site.[85] During the three-year data collection period, no local events above the 0 magnitude detection threshold occurred in spite of injection of 3 MMT of CO_2 and location elevation of pressure 1000 psi over initial pressure.

1.3.3 CO_2 injected for Enhanced Oil Recovery (EOR)

Most CO_2 EOR activity has been focused in the US in the Permian basin but the technique is possible globally.[86] Factors that favor use of CO_2 for EOR include favorable reservoirs with economically valuable remaining mobile oil light enough to be made miscible with CO_2, suitable stable supplies of CO_2 at economically viable, skills and equipment needed to add this much complexity to the production operation, and investors who understand the potential of this operation and favor the risk and pay out profile. CO_2 EOR requires substantial up-front capital to build pipelines, work over and prepare wells, and build a processing facility to separate oil, water and CO_2 and compress the CO_2 for reinjection. However the hydrocarbon resource is better known than some other types of hydrocarbon investment. CO_2 EOR is valuable to deep saline formation CCS in several ways: it provides a long and diverse experience in handlining large amounts of CO_2 (e.g. pipeline construction and operations, well preparation, experience in subsurface performance, risk profile); it has provided a mature offtake market for a number of early capture projects (examples in table 4); and it has given communities, regulators and investors experience with this type of operation. CO_2 EOR has also provided an experimental test bed for monitoring CO_2 retention in this setting.

EOR has been commercial since 1972, and the number of operations exceeded 100. Some operations have exceeded one million metric tons per year use, although this varies but field size, over time and by operator choices. A generalized overview of a typical EOR operation includes: a good quality light -intermediate weight oil field that has declining production after a phase of secondary production and infill drilling. An opportunity to bring the declining production back toward primary or secondary production maximum is attractive to investors who may include the current or a new operator. A study is done of the potentially recoverable resource, the amount, cost and availability of CO_2, and the cost and feasibility of infrastructure investment needed. After financial decision, if the field is not unitized, this is undertaken, and the capital outlay begins, taking a number of years. Injection and production wells are laid out in an optimized grid or line patterns in which some wells inject CO_2 or CO_2 alternately with water, known as water alternating gas (WAG). Some wells inject water to elevate pressure and steer fluids toward producers. Producers pump or lift under reservoir pressure, sending produced oil, CO_2 and water to test facilities, where each well's output is assessed sequentially, and then comingled. Fluids are then sent to the processing facility, where oil, CO_2, water, and depending on facility, light hydrocarbons such as propane and methane, are separated. Hydrocarbons are cleaned and sent to market, water is reinjected where it is needed, and CO_2 is cleaned and compressed for reinjection. Separation and reinjection of CO_2 is economically important to avoid high purchase cost for more CO_2, so the same CO_2 molecules are sent through the reservoir multiple times. In addition, the CO_2 may be contaminated with methane or H2S and may not be permitted for release. Details of each operators' choices are complex and may deviate from this path. Assessments show that the recycling process is quite effective, with release of less than 1% of the CO_2 throughput occurring mostly during intentional surface facility operations.[87,88]

Essentially no major CO_2 EOR operations have stopped production, although many individual wells and patterns with them have been removed from the operation. For example, it is common for parts of fields to transition from water flood to EOR and then back to water flood. Recently a number of CO_2 EOR operations have been qualified for storage tax credits under the IRS 45Q tax program. This program requires development of a Monitoring Reporting and Verification (MRV) plan as specified in the Clean Air Act (CAA) subpart RR and then reporting under this plan.[89] An equivalent plan under international CO_2 accounting standard ISO 27916 to document that retention is achieved has been added.[90] Examples of facilities with detailed reporting are shown in Table 3.

Table 3. Examples of Use of CO_2 for EOR Focused on Those with Reported Monitoring for Retention

Field name	Location	Main contributions	Citation
K12 B *	Offshore Netherlands	Early monitored CO_2 injection into a depleted gas field	Vandeweijer et al, 2018[91]
Lacq-Rousse *	Poe, France	Early monitored CO_2 injection into a depleted gas field	Total, 2015[92]
SACROC*	Scurry County, Tx	Early large-scale CO_2 EOR project, still operating. Hosted monitoring program that detected no leakage to USDW	Romanak et al, 2012[93]
Weyburn*	Alberta Canada	Large field developed using captured CO_2 that hosted a multi-institution monitoring program, giving many researchers access to injected CO_2, accept CO_2 from Sask Power Boundary dam	Whittaker et al. 2011[94]

Denver unit, Wasson #	TX	First project reporting an MRV plan under Clean Air act subpart RR	U.S. Environmental Protection Agency, 2015[95]
Hobbs Unit #	New Mexico	MRV plan	U.S. Environmental Protection Agency, 2017[96]
Hastings *	Texas	Monitored new EOR operation accepting offtake from Air Products SMR	Saini, 2017[97]
Petra Nova West Ranch * #	Vanderbilt, Texas	Monitored new EOR operation accepting offtake from Petra Nova capture, MRV plan	Kennedy, 2020 U.S. Environmental Protection Agency, 2021[98, 99]
Core energy Pinnacle reef complex * #	Michigan	Complex recycling and depletion patterns of hydraulically closed reefs.	U.S. Environmental Protection Agency, 2018[100]
Bell Creek*	Montana	Novel monitoring, staged development	Hamling et al., 2017[101]
North Burbank Unit #	Shidler, Oklahoma	MRV plan	U.S. Environmental Protection Agency, 2020[102]
West Seminole San Andres Unit #	Texas	MRV plan	U.S. Environmental Protection Agency, 2021[103]
Farnsworth Unit # *	Texas	MRV plan	U.S. Environmental Protection Agency, 2021[104]

More than 100 operating commercial EOR operations are not inventoried here, in part because public information is sparse. Some field-associated saline operations are reported in table 2 and not described here.

** Indicates that an R&D-oriented study was hosted at this field*

 # Indicates that public information about the operation and accounting is available from EPA as part of an MRV plan.

EOR is a complex operation and its role in mitigating CO_2 emission is complex, leading to widespread misunderstandings. One misunderstanding comes from a confusion between a petrophysics perspective, an operator perspective, and an accounting perspective. A petrophycist modeling CO_2 flooding of a core piece will note that about 1/3 to ½ of the CO_2 that is injected into the core piece is retained as residual saturation, with the other part flowing out of the downstream port of the core holder. Scaling this up, the operator will observe that about half of the CO_2 needed to recover oil has to be purchased from offsite, with the other half being made up of CO_2 that has been produced with oil, separated, and reinjected; this is called recycle. An accountant may misunderstand this statement, incorrectly assuming that the non-retained half is released to atmosphere. This is not correct for most operations, the other half is recycled in a closed loop, resulting in 100% retention except for deliberate operational releases or accidents.

A more difficult issue is the link between the CO_2 stored and the hydrocarbon produced. Physically, this is highly elastic – at one extreme is a depleted field storage-only operation during which no hydrocarbon is produced – at the other extreme is the current EOR operation where CO_2 is a cost so usage is minimized and oil is profit so production is maximized. The potential intermediates are sometimes described in terms of conversion of EOR to storage. The reality of such conversion depends on how reservoir pressure is managed with water injection and extractions.

A more nuanced view of oil production and CO_2 use in lifecycle analysis is presented by Núñez-López et al., 2017 and Núñez-López and Moskal, 2019.[105,106] Using reservoir models calibrated from EOR operations, they observe that the ratio of CO_2 stored to oil produced is high at the start of projects, when CO_2 is charging the reservoir for several years, and then declines as recycle begins to offset new purchase CO_2 but oil production continues. EOR projects with the boundary around the operation and the produced oil can be carbon negative at the initial phases but evolve to be carbon positive at maturity. If a negative carbon balance is to be maintained, a new field for EOR or storage must be brought into action to accept the CO_2 that was displaced by recycling.

The retention loss risk profile of EOR is quite distinct from a saline project. In a saline project, the greatest risk of loss of brine or CO_2 is that as the CO_2 plume and area of elevated pressure (AoR) increases in area it will encounter a conductive feature. It might also encounter an area of elevated risk of induced seismicity. In EOR, the area of elevated pressure and area occupied by CO_2 is highly engineered by the injection-withdrawal patterns. The operator has to balance the flood so that pressure remains in the window in which miscibility of CO_2 in oil is optimized, so the ratio of total fluid injection to total fluid withdrawal is stabilized at around 1. The area of elevated pressure is around the injection wells and drops toward the producers, not extending much into the off-structure water leg of the reservoir. The areas occupied by CO_2 are limited because CO_2 is drawn toward producing wells by pressure drop. In addition, the operator is collecting data to optimize production so that all the production wells in effect act as monitoring points. However, the risk of leakage along any of the numerous wells in the field remains a concern. A number of EOR projects have experienced episodes of CO_2 or brine loss related to well failures. These loss events are not very well documented, however losses such as those described at Delhi field Louisiana and Salt Wash field Wyoming are known.[107,108] In addition, much of the surveillance is in the best interest of the operator, however, there is little oversight or reporting except where it is put into a Monitoring, Reporting and Verification (MRV) plan for obtaining 45Q tax credits. Modeling for EOR is mostly focused within patterns because simulating interactions of the complex fluids and the pores are computationally expensive; modeling smaller areas is favored. This is in contrast to the extensive modeling required Under Class VI for saline injection. Optimum monitoring for EOR to document retention will therefore be quite different from saline optimum monitoring.

Depleted fields are somewhere between EOR and saline.[109,110,111] Use of a well-known rock volume in a known buoyant fluid trap reduces a number of uncertainties. Some of the most significant are detailed information about how this rock volume responds to fluid migration and pressure change collected during historic operations. A fluid flow model can be validated by production history matching before CO_2 injection begins, substantively increasing operational confidence. Infrastructure reuse and a public familiar with subsurface operations may be a significant benefit to the project, however it is important not to assume this is true but to conduct a detailed assessment.[112] The boundary conditions of a depleted field are important to its function. Some depleted fields are nearly hydrologically closed and may be strongly pressure depleted, providing initial very secure storage where all the driving forces are inward to the field. However, the capacity of such fields is limited. Other fields may have good edge-water drive and have been depleted in terms of mobile hydrocarbons but not strongly pressure depleted. In this case a depleted field acts more like a saline aquifer. Imbibed brine must be displaced and CO_2 can migrate downdip if pressure differentials are greater than buoyancy forces in some zones.

In both open and closed boundary conditions, the geomechanical impact of changes in pressure on reservoir seals and wells that penetrate the seals must be critically considered in depleted fields. In weak brittle chalk rocks, depletion is known to have deformed the overburden.[113] It is unclear how widespread this effect is. In addition the number and condition of wells must be considered potentially even more critically than in saline aquifer conditions, because in a structural trap the CO_2 column height will increase over time as brine is displaced, although pressure from injection may decline.

1.3.4 Gas Storage

Gas storage is another partial analog for CO_2 storage for which a number of incidents and failures are known and can be used to inform and manage CO_2.[114] However, the analog is incomplete. Pressure management strategies have a major impact on the performance and stability of the storage field. Gas storage cycles frequently from charge to depletion. Therefor the areas near the well(s) are subject to dry out during repeat charging events; this can either enhance or limit permeability near the well. In the US, gas storage is permitted outside of the UIC program and local jurisdiction has resulted in variation in standards. For example the failed well at the Aliso Canyon gas storage site, near Los Angele, California was not operated like a UIC well with double-wall casing-tubing packer system.[115] If such a system had been in place, the operators would likely have identified casing damage early because of loss of annular pressure prior to significant leakage. Further, well remediation using the tubing and annulus would likely have been more straightforward and therefore faster.

2. Moving as Fast as Possible to Build Investor Confidence

Three steps are suggested as actions to build investor confidence:

1. Making the existing records on large volume injection more accessible
2. Document and make available the processes and procedures that are sufficient to demonstrate confidence in a storage effectiveness
3. Investment in projects that collect and provide data on storage performance

2.1 Making the existing records on large volume injection more accessible

One relatively easy way to improve investor confidence is to aggregate more of the injection experience available in the more than 50-year history of injection. In particular industrial experience with Class I well operation, which is closest to Class VI operation, could be gained by a relatively low budget data amalgamation effort extracting and digitized data held by the various state and federal regulators. An analysis of this experience could both better inform investors about the risks and bottlenecks in these types of permitted operations as well as expose both the maturity of the US regulatory system and its limitations that then could then be better mitigated.

2.1 Document and make available the processes and procedures that are sufficient to demonstrate confidence in a storage effectiveness

Poor definition of costs and timeline for obtaining and maintaining permits cause investor uncertainty. In developing Class VI, EPA was advised to keep the rule non-prescriptive and require site- and project-specific matching of approach to local conditions. However, this needed flexibility also generates uncertainty and creates a prolonged negotiation between the project developer and the regulator to develop a consensus on the sufficiency of the permit approach. Experience is one way to reduce this uncertainty. Other approaches might include a well-defined workflow for documenting the sufficiency of the characterization, monitoring and closure as well as defining the financial assurance needed. Class VI does not require risk -based approaches, however risk mitigation processes such as bow tie or scientific method-based assessments could speed negotiations by setting ground rules against which flexible requirements can be assessed.[116,117]

One specific investment uncertainty was identified in a recent study.[118] 3-D seismic is by far the most expensive item on the geologic characterization and monitoring portfolio. However, it is unclear under what conditions this data is needed and over what areas must be collected. The data content and value vary significantly depending on the geologic characteristics of a site. In some sites it clarifies complexities and reduces risk, in other sites it is relatively unrevealing. In some sites, definition of boundary conditions rather far from the area occupied by CO_2 may be the most critical elements triggering the near for large area surveyed at high cost; in other settings seismic data may have small value in reducing uncertainty and not be needed at all. Experience and guidelines to determine how much of this highest cost element is needed will add investor confidence.

2.1 Investment in projects that collect and provide data on storage performance

The most compelling way to add investor confidence is subsidizing investment in more projects to move CO_2 storage for mitigation from first-of-a-kind to "nth-of-a-kind. The more transparent these development projects are, the greater the lessons learned and the higher the value. However, full-scale long-term projects are expensive, and confidence will be built over time.

Most previous field tests and commercial projects have been developed in favorable locations where confidence in project success was high at the outset. However, some of the most valuable learnings have been from mistakes or accidents that probe the limits of success and define what has to be managed. Examples of such problems have been overpressure opening fractures at the Salah, the mitigation of the pressure increase at Snøhvit, and the management of micro seismicity at Decatur.[119] Controlled release "planned failures” have resulted in more reasonable near-surface monitoring expectations and improved the ability of project operators to respond to concerns from stakeholders. The value of these experiences highlights the need for more real-world experience with failure and mitigation so that likelihood and cost can be correctly assessed. More experience with mitigation such as rapid identification and mitigation of existing wells that are not sufficiently isolating are needed, especially in cases where the well has been plugged and abandoned and is inaccessible to downhole tools. Techniques for rapid and confident evaluation of the performance of vertically transmissive fracture sets and faults are needed. Experience is needed in reservoirs with limited injectivity to optimize opportunities in areas that lack high quality injection zones. Qualification of confining systems that are heterogenous is likewise needed. Validation of assumptions and models for pressure interference from large volume injection using adjacent parts of the subsurface is needed. More field testing related to predicting, assessing and managing geomechanical issues to define and avoid unacceptable seismicity is needed. All injection will have some geomechanical effects and in most locations this is acceptable because impacts on the surface are negligible. However, mechanisms for assuring that avoidance and mitigation of unacceptable outcomes are needed.

On the low frequency but high impact end of the spectrum of needs, a model and field validated catalog of best practices in well control is needed. Well control refers to effective procedures for preventing and “killing” blowouts.[120] Recommendations of effective mitigation are needed that can be shared among all operators entering commercial storage operations. Because CO_2 has complex phase behavior in conditions relevant to blowout, further assessment is needed to increase confidence that low likelihood but serious errors in well management can be quickly and confidently corrected.

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