Scientific considerations related to regulation development for CO_2 sequestration in brine formations

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Abstract Carbon management through the underground injection of CO_2 into subsurface brine formations is being actively studied. If there are no technological constraints for implementation, there could be a large number of wells constructed for injecting a large volume of CO_2. It is therefore important, in parallel with current scientific studies, to consider the appropriate, science-based regulatory framework for CO_2 injection. The Environmental Protection Agency (EPA) Underground Injection Control (UIC) program, authorized under the Safe Drinking Water Act (SDWA), has extensive experience in regulating the injection of mainly liquid wastes into geologic formations in the United States. The federal requirements and permit process implemented by EPA and the Primacy States since 1980 have played a critical role in the safety of subsurface disposal of liquid wastes in the US. Physically and chemically, there are significant differences between CO_2 and common liquid wastes. Its viscosity and density are much lower and, under injection pressure in the deep formation, it may be under supercritical conditions. Because of the lower density and viscosity, CO_2 leakage through the confining strata may be greater when compared to currently injected liquid wastes. Also, the chemical interactions of CO_2 with the geologic formation have their own characteristics. All these scientific factors need to be evaluated to identify new guidelines for appropriate regulatory and monitoring controls. The paper reviews current UIC regulations, injection-well classification scheme and monitoring requirements, and identifies the unique factors related to the physical and chemical processes in the subsurface associated with CO_2 injection. Implications of these scientific considerations for regulation development are discussed.

Keywords Regulation · CO_2 · Sequestration · Brine injection

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Introduction

Reduction of atmospheric emissions of CO_2 (DOE 1999a) through injection of CO_2 into deep brine formations is being actively studied both in the USA and internationally. If this technology is to be employed broadly enough to make a significant impact on global emissions of CO_2, thousands of wells, each injecting large quantities of CO_2, will be needed. For example, in the US alone the coal-fired electric generating capacity in 1999 was 278,000 MWe (DOE 1999b), and a coal-fired plant with 1,000-MWe capacity generates about 30,000 tonnes of CO_2 per day (Hitchon 1996). Thus, there is need for a careful evaluation of the issues which should be addressed by a regulatory framework for such a large-scale endeavor. This includes (1) a realistic appraisal of the risks associated with CO_2 sequestration, (2) recognition and incorporation of the best scientific understanding of the process of CO_2 injection and migration in subsurface formations into the regulatory approach, and (3) innovations in monitoring technology to ensure that geologic sequestration is safe and effective. The purpose of this paper is to review the Environmental Protection Agency (EPA) Underground Injection Control (UIC) program in the context of CO_2 sequestration or storage in brine formations. The Underground Injection Control program, authorized under the Safe Drinking Water Act (SDWA) of December 1974, has extensive experience in regulating the injection of liquid waste in geologic formation in the United States. In this paper, we first give a history of liquid waste injection in the US and the essential elements for regulation and monitoring requirements. Then, the special physical and chemical characteristics of CO_2 in contrast to liquid waste will be discussed. Implications for regulatory control and monitoring requirements based on these characteristics will be presented.

History of waste disposal by injection wells in the United States

The practice of using injection wells for waste disposal started in the oil fields in the 1930s when depleted reservoirs were used for the disposal of brines and other waste fluids from oil and gas production. The first report of injection of industrial waste was published in 1939 (Harlow 1939). The literature indicates only four such wells in 1950. A 1963 inventory by the US Bureau of Mines listed 30 wells (Donaldson 1964). Most of these early wells were converted oil production wells. By the early 1970s, the number of injection wells had grown to approximately 250 (Warner 1972), and they were being used to dispose of municipal sewage effluent as well as industrial wastes.

A number of well integrity failures in the 1960s and 1970s have been documented (Lehr 1986). These included contamination of a drinking water aquifer in Beaumont, Texas, due to an injection well which did not have a separate injection tube within the well. The injected waste caused corrosion of both the inner and outer casings and the surrounding layers of cement, resulting in leakage from the injection well. In Odessa, Texas, an injection well was clogged due to precipitation of two incompatible waste streams and surface injection pressures quickly exceeded the allowable limits. In Denver, Colorado, injection activated seismic events in a fault zone, which allowed injected liquids to escape through rock fractures and facilitated minor earthquake activities.

Concerns about the safety of deep injection disposal led the US EPA to issue a policy statement in 1974 which opposed storage or disposal of contaminants by subsurface injection "without strict control and clear demonstration that such wastes will not interfere with present or potential use of subsurface water supplies, contaminate interconnected surface waters or otherwise damage the environment". In December 1974, Congress enacted the Safe Drinking Water Act (SDWA), which ratified EPA policy and required the agency to promulgate minimum requirements for state programs which would prevent endangerment of underground sources of drinking water by well injection.

In 1980, pursuant to the mandate established by the Safe Drinking Water Act, the US EPA promulgated federal regulations which established minimum requirements for state UIC programs. These regulations are implemented by individual states, where state laws and regulations are adequate, or by the US EPA in states choosing not to obtain approval of their UIC program. In the former case, state UIC programs are sometimes more restrictive than the minimum federal class I requirements. Under the regulations developed in the 1980s and 1990s by the EPA and the individual states, no significant well failures have occurred. By 2000, there were 485 deep injection wells in the US for disposal of industrial liquid waste.

When Congress enacted the Hazardous and Solid Waste Amendment in 1984 to the Resource Conservation and Recovery Act (RCRA), a new burden was imposed particularly on "hazardous" waste injection wells. The amendment specifically prohibits the continued injection of untreated hazardous waste beyond specified dates – unless the EPA Administrator determines that the prohibition is not required to protect human health and the environment for as long as the wastes remain hazardous. In 1988, the UIC regulations were amended to comply with this new mandate. Operators of hazardous waste injection wells must now demonstrate to the US EPA, through the use of computer models, that hazardous wastes will not migrate out of the injection zone for at least 10,000 years. This demonstration can be based either on flow modeling or on the modeling of waste transformation within the injection zone.

Regulation of underground injection wells

EPA-UIC regulations require protection of current and potential sources of drinking water. They define underground sources of drinking water (USDW) as aquifers which supply any public water system or contain water with less than 10,000 mg/l total dissolved solids (TDS) in sufficient quantity to serve as a public water system.

All injection wells fall into five classes of wells according to regulations established by the federal UIC program:

1. Class I. Injection of municipal or industrial waste (including hazardous waste) below the deepest USDW.
2. Class II. Injection related to oil and gas production, including enhanced hydrocarbon recovery and hydrocarbon storage.
3. Class III. Injection of fluids for the extraction of minerals.
4. Class IV. Injection of hazardous or radioactive waste into or above a USDW (banned by regulation and statutes).
5. Class V. All other wells used for injection of fluids. These are generally shallow wells used to inject nonhazardous fluids into or above a USDW.

Regulations are tailored to the different classes of wells. In general, the regulations for class I, II, and III wells establish siting, construction, operating, testing, monitoring, and reporting requirements. In addition, owners and operators of these injection wells must demonstrate the financial capability to properly plug and abandon the wells upon completion of operations. The regulations are stringent and specific for class I wells, particularly those which inject hazardous wastes; they are more flexible for class II wells. Class IV wells are banned, with the exception of wells used for remediation of aquifers which have been contaminated with hazardous wastes.

Among the five classes of injection wells the most relevant to CO_2 injection into brine formations is the class I wells. It appears likely that CO_2 storage will be required to be below the deepest USDW whenever possible. This is consistent with the desire for deep injection to store CO_2 in a supercritical state, which avoids the adverse effects from the separation of CO_2 into liquid and gas phases in the injection zone. The critical point of CO_2 is at a pressure of 73.82 bar and temperature of 31.04 °C (Vargaftik 1975), which exists at depths below about 800–1,500 m, dependent on local land surface temperature, heat flow and sediment lithology (Bachu 2000a).

For class I wells, UIC regulations require the submission of detailed geologic and hydrologic data. These data are used to determine whether injection will take place in a receiving formation which is (1) relatively homogeneous and continuous, (2) free of transmissive faults, and (3) separated from USDWs by at least one, but preferably several, thick and relatively impermeable strata. It is also required that the location of the injection well will not be in a seismically active region. The regulations require the applicant to demonstrate that all unused abandoned wells in the vicinity of the proposed injection well are properly completed and plugged, so that they will not serve as a conduit for injected waste or displaced formation fluids.

Another important factor for class I injection wells is proper well construction. The UIC requirements were designed to achieve two goals: protection of USDWs, and successful emplacement of the waste in the chosen injection interval. A typical class I injection well constructed according to UIC requirements has at least two strings of casing. The surface casing is designed to protect USDWs, and the long-string casing is extended to the injection zone. These casings must be cemented to the well bore in order to prevent movement of fluid into or between USDWs. Ideally, wells are equipped with an injection tubing set on a packer located above the injection zone to prevent backflow of injected waste into the well. Materials used in well construction must be resistant to the proposed injected waste and to formation fluids. Before a well is put into operation, the effectiveness of the cementing program must be verified by logging the well (i.e., lowering tools into the well with electrical sensors which measure such variables as temperature, noise, and particle emissions). Similarly, the integrity of the well's tubular system must be verified by pressure tests.

For proper operation of class I wells, the EPA regulates injection pressure to ensure that the well and the confining formations are not damaged. The regulations require the maximum injection pressure to be specified and set below the fracturing pressure of the injection zone, which ensures that the confining zone cannot fracture. Injection pressure, injection volume, and flow rate must be continuously monitored, as any change in the relationships between these variables could indicate downhole problems. The tubing-casing annulus must be filled with fluid with an applied positive pressure. Continuous monitoring of this pressure is required to detect leaks in the tubing, packer, or long-string casing. If a pressure change indicates a leak, the well must be shut down, and further testing conducted to verify the cause of the pressure change. The well must remain shut down until all problems are resolved. A simultaneous failure of at least two of these elements would be necessary for waste fluid to escape the injection well; the conditions under which both these failures could lead to contamination of a USDW are unlikely.

Proper operation also requires the injected waste to be compatible with injection formation matrix and fluids. This requirement often works to the advantage of the operator, because incompatibility between these elements could cause the formation of precipitates which plug the formation face and reduce the useful life of the well. In some cases, however, such as injection of acid waste in carbonate formations (which can result in the formation of carbon dioxide), the waste injection must be managed to prevent sudden releases of gas and well blowout.

Finally, the EPA determined that proper plugging and abandonment of the wells was important in ensuring that injected wastes would not travel back to the surface when injection is terminated. Regulations require the operator to submit a plugging and abandonment plan as part of the permit application. This plan must identify the number and method of placement of plugs in the well. The operator must also demonstrate that he or she is, and will remain, financially capable of properly plugging the well.

Monitoring requirements

Under current UIC regulations for class I injection wells, separate monitoring wells are not required. The argument is that the most potential leakage pathways are concentrated in or around the injection well, because the injection pressure decays rapidly with distance from the point of injection. Thus, even if there is a relatively high-permeability leakage path in the confining layer above the injection zone some distance from the injection well, the driving force (pressure at the location) is relatively small to cause a large leakage (Miller and others 1986). Another argument is that a randomly placed monitoring well has statistically low probability of success, so that a monitoring well should only be placed on the basis of an identified potential leakage pathway (Warner 1992).

The logs and tests required for class I injection wells are outlined below.

Continuous monitoring

1. Injection flow rates
2. Injection pressures

One-year intervals

1. Radioactive tracer log (RTS-I^{131})
   - Pathway of injected waste
   - No upward migration channels by casing/cement shoe
2. Annulus pressure testing
   - Pressure up-annulus (500–1,000 psi) to verify no casing, tubing and packer leaks

- May also run OA log to verify leaks (optional). Temperature and noise logs may be used in combination, especially where a RTS anomaly has been discovered

3. Reservoir testing
   - Pressure fall-off test to determine characteristics of injection zone, etc.
   - Well(s) must be shut in for a period of time to make valid observation

Five-year intervals

1. Temperature log
   - Must run for entire length of casing
   - Check for inter-formational movement of fluids
2. Casing inspection log (CIL)
   - To check for loss of casing material
   - Check for corrosion
3. Cement bond log (CBL)
   - Check zone for isolation of waste
   - Well construction/loss of cement

Well plugging

1. Run mechanical integrity test logs: RTS/temp/noise/OA
2. For final well plugging run, CIL and CBL before plugging well

Other logging tools for safety

1. Open-hole logs
   - E-logs, SP log (dual induction), neutron logs, micro-E-logs, fracture logs
2. Repeat formation tester (RFT)
   - Open hole fluid sample
   - Sample injected water from other wells
   - Collar location (CBL, temperature, casing, and CIL)
3. Thermal decay tool (TDT)
   - To determine cavity top outside casing
4. Sonar caliper log
   - To determine cavity size and direction

Note that nearly all the tests and logs, except for "reservoir testing" under "one-year intervals" and operational data under "continuous monitoring", are concerned with the mechanical integrity of the injection well construction and the conditions in the immediate neighborhood of the well.

Special physio-chemical properties of CO_2 and their implications for regulation and monitoring needs

CO_2 sequestered by injection in a deep brine formation will be stored in three forms: a dense supercritical gas phase, a dissolved state in pore water, and an immobilized state through geochemical reaction with in-situ minerals (Hendricks and Blok 1993; Bachu and others 1994). The fraction of pore space available for sequestration varies widely from 2–6% estimated by van der Meer (1995) to the range of 20–30% calculated by Pruess and others (2001a). The dissolved-state storage capacity factor is estimated to be from 2% in saturated NaCl brines to 7% in dilute water. CO_2 immobilization in formation matrix minerals is a very slow process and varies considerably with rock types. The amount of CO_2 sequestered through such mineral reactions can be comparable with CO_2 dissolution in pure waters.

Ennis-King and Paterson (2000) suggested that CO_2 can also be trapped as a residual gas during its migration through the formation. There is a saturation level below which CO_2 is trapped by capillary forces and ceases to flow. This trapped CO_2 will eventually dissolve in the pore water. The saturation level at which CO_2 is thus trapped is 5–30%, as deduced from typical relative permeability curves, and this is comparable to the density of CO_2 dissolved in the formation water. However, this process is only important at later times after the injection operation, when CO_2 saturation decreases or when CO_2 escapes from the storage zone.

Among all the forms of CO_2 sequestration in the injection brine formation, the supercritical gas phase is the main storage form and has properties quite different from those of pore water in the injection formation. Thus, for storage of CO_2 at 1,000-m depth, its density is about 60–75% that of water in the formation and its viscosity is about 15–20 times less than that of water (Vargarftik 1975).

The lower density of the stored supercritical CO_2 will cause buoyant flow of CO_2 to the top of injection zone below the caprock. The flow depends on the density difference as well as the vertical and horizontal permeabilities of the formation. Hellström and others (1988) give a measure γ of forced convection flow compared with buoyancy flow as

$$\gamma = \frac{Q_1\,\overline{\mu}}{H\,\sqrt{k_x k_z}\;g\Delta\rho} \qquad (1)$$

where Q_1 is the forced convection flow under injection pressure across the thickness H of the injection zone and for unit length in the third dimension, $k_x k_z$ is the product of horizontal and vertical permeabilities, g is the gravitational constant, $\Delta\rho$ is the difference in density between pore water and supercritical CO_2, and $\overline{\mu}$ is their average viscosity. The formula is essentially the same as the ratio of viscous to gravity effects ($R_{v/g}$) divided by the parameter accounting for anisotropy (R_L), given by Ennis-King and Paterson (2000) in their discussion of CO_2 sequestration. Equation (1) is a simple formula showing that the importance of buoyancy flow ($1/\gamma$) is proportional to the geometric mean of the vertical and horizontal permeabilities, the thickness of the formation, and the density difference, but is inversely proportional to the injection flow rate and the mean viscosity of in-situ brine and the supercritical CO_2.

Because of buoyancy flow of CO_2 to the top of the injection formation, the areal extent of the injected CO_2 will be larger than a buoyancy-neutral fluid. For example, storage of 2.7×10^{11} kg CO_2, at a rate of 350 kg/s for 30 years in a 100-m thick formation with k_x=10^{-13} and k_z=k_x, will have an increase in areal extent due to buoyancy flow of approximately 1.4 (Pruess and others 2001a). In this example, because of the large volume of CO_2 involved, the areal extent of the supercritical gas in the injection zone can be as much as 120 km^2.

In the case of deep injection disposal of industrial liquid waste, the liquid can have density values higher or lower than that of formation brine, though typically the difference is less than 10%. However, the buoyancy flow may still be very significant because the injection flow rate Q_1 is relatively small (see Eq. 1). In a typical example provided by Miller and others (1986), the injection rate is 150 gpm or 95 kg/s into a 325-ft formation, and the increase in radial distance from the injection well, due to buoyancy flow, is estimated to be by a factor of 1.75 after 10 years of injection, but the area covered by the injected liquid is only about 0.3 km^2.

The density of liquid wastes for injection disposal is typically 1,000 to 1,200 kg/m^3, which is to be compared with a density of 600–750 kg/m^3 for supercritical CO_2. Thus, in the liquid waste injection case, the buoyancy force to drive the injected liquid up through a leakage path in the caprock would be relatively small. A more important driving force is the injection pressure at the disposal well, which is large mainly within a region close to the injection well. For CO_2 injection, on the other hand, the buoyancy driving force is much larger to induce upward leakage of CO_2.

Ennis-King and Paterson (2000) considered the question of the thickness h of the layer of CO_2 needed to provide enough buoyancy pressure to exceed the gas entry pressure of the caprock. Using a capillary model of the porous medium, h may be given by

$$h = \frac{2\sigma}{\Delta\rho g r} \tag{2}$$

where σ is the surface tension between CO_2 and water, and r is the effective pore radius. Ennis-King and Paterson (2000) estimated h to be 70–170 m for r=10^{-7} m. However, if there exists a fracture in the caprock, the effective r in the fracture can be much larger, and the thickness of CO_2 required to overcome the gas entry pressure of the fracture would be much less. Pruess and Garcia (2001, this volume) made a numerical study of potential leakage through a vertical fracture and found it to be significant, due not only to the lower density and viscosity, but also to the two-phase flow effect. The CO_2 effective permeability in the vertical leakage path will increase as the saturation of CO_2 in the vertical channel increases, resulting in a faster leakage flow. This preliminary evaluation indicates that a more complete study of caprock leakage is needed to provide a full understanding of the process and its implication for CO_2 sequestration.

The screening criteria for selecting a site suitable for CO_2 injection have been discussed by Bachu and Gunter (1999), and Bachu (2000b). They are largely similar to those of deep injection disposal of liquid industrial waste (Warner and Lehr 1977). However, as discussed above, the area of storage covered by CO_2 is large and can be $\sim$120 km^2 in the example quoted above from Pruess and others (2001a). Thus, a much more extensive evaluation of the integrity of caprock and the existence of possible faults and fractures is needed. Methods for evaluating caprock integrity have been developed for aquifer gas storage applications (Witherspoon and others 1967) and are likely to be applicable here. However, new methods which provide caprock characterization over very large areas are likely to be needed. Geophysical techniques, including satellite-based, land surface deformation monitoring, will be helpful.

The very low viscosity of supercritical CO_2 will give rise to flow instability at the CO_2-brine interface as CO_2 is being injected into the storage formation. This flow instability results in fingering. In other words, instead of a piston-like flow of the CO_2 front into the injection formation, parts of the front will flow much faster in the form of fingers. This phenomenon was well studied (see, for example, Chang and others 1994) and is in competition with the buoyancy flow effect discussed above (Crane and others 1963; van der Meer 1995).

Another type of fingering or channeling effect occurs because of heterogeneity of the injection formation. The injected CO_2 will be channelized to follow the most permeable paths because of the spatial variation of permeability (Tsang and others 2001). The flow pattern will depend not only on the permeability variability and its spatial correlation range, but also on the saturation level of CO_2 in the different parts of the brine formation. Based on empirical information and analytical considerations, a rough estimate of the extent of injected fluid accounting for heterogeneity and stratification was proposed by Tsang (1996) in the case of injection disposal of liquid wastes:

$$\frac{r'}{r_0} = 2.3\, e^{(1-n)\sigma} \tag{3}$$

where r' and r_0 are the radial extent of injected fluid with and without the effect of heterogeneity and stratification, respectively, σ is the standard deviation of log permeability mean values over the stratigraphic layers, n=0 or 1/3 corresponding to porosity being independent of permeability or varies as its cube root, and the factor 2.3 represents the influence of flow channeling due to heterogeneity within each stratigraphic layer.

Chemically, there is also a difference between CO_2 injection and injection disposal of liquid waste. For the latter, the liquid waste will interact with the formation system and, if it is acidic, its acidity will be neutralized after a time period. For the case of storage of supercritical CO_2, the acidity will persist for a long time, slowly degrading the rock matrix. The long-term impact still needs to be studied. Furthermore, at the CO_2 front where CO_2 is dissolved in water, minerals such as calcite may dissolve readily, leading to an increase in permeability and porosity along the flow channel. This leads to a higher flow rate and increased dissolution, forming what is known as wormholes (Ross and others 1981; Mathis and Sears 1984). On the other hand, based on the experiences from enhanced oil recovery, CO_2 has been known to reduce injectivity in some cases (Czernichowski-Lauriol and others 1996) but to increase permeability near injection wells in others, such as in carbonate reservoirs (Holm 1959; Ross and others 1981). There are also data indicating that dissolved CO_2 will cause a reduction in permeability where the carbonate minerals precipitate along the flow paths with a large pressure gradient (Czernichowski-Lauriol and others 1996). All these observations suggest the need for careful evaluation of the compatibility between supercritical CO_2 and geochemistry of the brine formation. Such an evaluation may also yield information useful for the design of injection operation, such as keeping injection pressure below a value so that there will be no severe pressure gradients to induce precipitation or dissolution. The associated regulatory control and monitoring deserve further study.

With CO_2 sequestration at or below a depth of about 1,000 m, there may well be a sequence of intervening strata of confining and permeable layers separating the injection zone and the lowest USDW. This sequence of strata can provide a compound margin of safety to reduce CO_2 upward leakage. Thus, each permeability layer can act as an injection zone for CO_2 leaking into it from below and spreading in it. Then, the next overlying confining layer will act as the next caprock to prevent continuing CO_2 leakage. The concept was proposed by Miller and others (1986) for deep injection disposal of liquid waste, but is probably more applicable for the sequestration of CO_2 in brine formations. Regulatory aspects associated with this proposal need to be studied.

Given the fact that monitoring wells are likely to be needed for CO_2 sequestration, an important issue is how to locate the optimal sites for monitoring wells. Warner (1996) discussed the use of monitoring wells (1) within the injection zone, (2) within the first aquifer above the injection zone caprock, and (3) in the USDW above the injection zone. Selection of their locations requires some indication of the possible locations of potential leakage paths. This can be obtained by a combination of reservoir modeling, geophysical surveys such as three-dimensional seismic, electrical imaging and gravity surveys. All of these technologies are fairly mature and are applicable here.

A useful point to note is that a minor leakage of CO_2 into an overlying aquifer or into the atmosphere may not be a major environmental problem. In fact, in some cases, slow leakage of CO_2, followed by dissolution and possibly even mineralization of the CO_2 in overlying formations, may be a desirable strategy for controlling reservoir pressures and limiting long-term impacts of CO_2 sequestration. Thus, there is no need for a no-migration requirement for CO_2 sequestration in brine formations. An alternative approach would use a careful evaluation of the hydrogeologic setting and model simulations to ensure that cumulative and instantaneous releases of CO_2 to the environment are within prescribed limits and do not compromise sequestration effectiveness. Models for making these types of calculations are currently available and are being improved through the efforts of many researchers around the world (Pruess and others 2001b). Model results can then be used to support risk-based approaches for environmental decision-making (Ruckelshaus 1983; National Research Council 1994; Kammen and Hassenzahl 1999).

Concluding remarks

This paper reviews current EPA-UIC regulations and monitoring requirements in the light of potential applicability to large-scale geologic sequestration of CO_2 in brine formations. Special physio-chemical properties of CO_2 injection related to appropriate regulations are pointed out. These include:

1. Density being lighter than surrounding fluids, resulting in buoyancy driven flow;
2. Viscosity being much lower than surrounding fluids, resulting in flow fingering and other effects;
3. Possibility of stratified flow and channeling due to formation heterogeneity;
4. Chemical interactions altering permeability near the well or at locations with large pressure changes;
5. CO_2 plume covering a large area, requiring caprock evaluation over an extensive area;
6. Low concentrations of CO_2 being not harmful; and
7. Some degree of leakage can be allowed and incorporated into regulatory approach.

While certain techniques are now available to study many of the above elements, new or improved methods and testing techniques will be needed to enable large-scale geologic sequestration of CO_2. Furthermore, as pointed out above, certain physical and chemical processes particular to CO_2 sequestration in brine formations still need careful studies to provide an advanced understanding so that appropriate regulatory guidelines and monitoring strategy can be determined.

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