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Carbon Capture, Sequestration and Enhanced Oil Recovery: Potential Opportunities and Barriers in the Context of Geologic and Regional Factors

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Carbon Capture, Sequestration and Enhanced Oil Recovery: Potential Opportunities and Barriers in the Context of Geologic and Regional Factors

Executive Summary

Thank you for the opportunity to testify about potential incentives and barriers associated with carbon capture and sequestration. My name is Brian McPherson and I specialize in geology, geophysics and subsurface hydrology. For the past 10 years, I served as a professor of hydrogeology at New Mexico Tech. For the past 3½ years I have served as PI and Director of the Southwest Regional Partnership on Carbon Sequestration, a consortium sponsored by the U.S. Department of Energy along with six other regional partnerships. At this time, I am employed at both New Mexico Tech and the University of Utah.

The general premise of geological CO_2 sequestration is to

(1) separate CO_2 from power plant flue gases,
(2) capture that CO_2 in a separate stream,
(3) compress the CO_2 to elevated pressures to maximize its density,
(4) inject the CO_2 into subsurface geological formations ranging from 2,500 to 20,000 feet depth.

Target storage reservoirs are porous and permeable rock layers, overlain by low-permeability confining layers. Such geologic reservoirs have contained brine, oil and natural gas for millennia, and thus using these reservoirs for storing CO_2 is a very viable concept. Target reservoirs are commonly classified by what type of fluid they hold, including:

- *Depleted oil and gas fields:* Injection of CO_2 into these reservoirs can enhance oil recovery (EOR) or gas recovery (EGR);
- *Deep unmineable coal seams*: Injection of CO_2 into these reservoirs can enhance gas recovery (EGR);
- *Deep saline formations*: classified as reservoirs with brine salinities greater than 10,000 ppm; injection into these reservoirs is preferred by many because the brine is not useable for other purposes.

With a robust confining layer, sequestration duration can be maximized and risk minimized. With respect to engineering, such CO_2 injection has been done for decades in many areas of the U.S., for enhanced oil recovery. Thus, the engineering and technological details are relatively mature.

At the moment, 25 field geologic sequestration demonstration tests are being designed and scheduled for deployment in the U.S. over the coming 3 years. An additional 20 or so are ongoing or slated for deployment soon in other countries. Most of these tests are using different technologies, including different engineering designs, different monitoring approaches, different risk assessment protocols and different mitigation strategies. And, most of these tests are relatively small in scale: small injection rates compared to typical power plant emissions output. The uncertainties associated with evaluation and design of large-scale sequestration operations are significant. For large-scale geologic sequestration to be deployed and sustainable over the long-term, a realistic, field-based evaluation of uncertainties, and how these uncertainties affect risk assessment and mitigation strategies, must be carried out. Additionally, the community also needs a meaningful assessment of CO_2 trapping mechanisms and the physical and chemical factors that may cause the mechanisms to lose efficacy under realistic (field) conditions. Next

year, the U.S. will begin deployment of several commercial-scale sequestration deployment demonstrations. These will sequester up to 1 million tons/year, the scale of a typical power plant's emissions, with a scheduled duration of 5+ years. These tests will provide a good deal of the data required to maximize storage capacity and minimize uncertainty associated with commercial-scale sequestration, but not all of it. Therefore, I suggest that incentives may be needed to provide the huge amount of data needed to ensure commercial sequestration is robust and safe. Furthermore, I suggest that new incentives are needed to motivate industry to take on commercial sequestration as a routine part of business. I list these suggestions here.

(1) First, I recommend incentives that will stimulate sequestration operations, with some assigned greater priority than others. Specifically: I suggest that greatest priority and incentives be assigned to deep saline formations underlying oil/gas fields, to maximize relevant characterization data availability and monitoring opportunities. Next in the priority list would be deep saline formations not underlying oil/gas fields. Finally, the priority list and incentive ranking should include CO_2 injection in oil and gas reservoirs with maximized sequestration and minimized CO_2 recycling.
(2) I recommend incentives that will assist with providing the data necessary for liability, risk and capacity assessments associated with sequestration. Specifically, oil/gas and other entities hold a huge amount of data privately, and these data are essential to providing robust assessments of capacity and risk. The DOE's Regional Partnerships, in collaboration with state geological surveys and the USGS, are gathering a great deal of data and assembling them for the public in the form of NATCARB, a national carbon sequestration database. If added, privately held data would likely more than double the size of that database, and as well would double our ability to assess capacity and risks of sequestration.
(3) I recommend that areas of the country that lack CO_2 pipeline infrastructure be provided incentives for building such pipelines. For commercial-scale sequestration to move forward, infrastructure will be necessary.
(4) I recommend incentives for state-, federal- or privately-sponsored indemnification. The states of Illinois and Texas assembled comprehensive indemnification plans for FutureGen, and these plans may serve as a template for future liability associated with commercial sequestration.
(5) The U.S. lacks a fully resolved regulatory framework. Any planned incentives for sequestration and EOR should factor in the evolving regulatory framework being developed by the EPA, the Interstate Oil and Gas Compact Commission, the Regional Partnerships, and individual states.

Thank you again for this opportunity to speak to you today. I look forward to any questions you may have.

1. Potential Opportunities for Geologic CO_2 Sequestration

Enhanced Oil Recovery and Sequestration

In many areas of the United States, enhanced oil recovery (EOR) is a potential driver for carbon storage. The basic premise of CO_2-based EOR is to inject CO_2 into an oil reservoir, which will reduce the viscosity of oil and facilitate easier production. Some of the injected CO2 comes back to the surface with the produced oil, where it is separated from the oil and reinjected to continue the EOR process.

EOR generates profits from the sale of the produced oil. As a result it is a strong motivator for carbon storage and should be encouraged. I would like to see incentives for companies to maximize the ultimate storage of carbon dioxide in these reservoirs at the end of a field's useful life. While there is a small possibility for CO_2 to leak to the surface through abandoned wells, this drawback can be offset through regulatory and monitoring requirements.

Deep Saline Formation Sequestration

The capacity of deep saline formations – these are deep rock units filled with water which contains high levels of salts and minerals and is well below drinking quality standards – in sedimentary basins tends to be much greater than that for typical oil/gas fields, and thus these are preferred targets for sequestration. Additionally, oil and gas fields have the potential of CO_2 leakage because of abandoned wells, as mentioned above, whereas deep saline reservoirs possess few or no such wells.

Since deep saline formations represent a low-risk, high capacity storage site for CO2, I recommend using tax incentives or other means to stimulate storage in these formations. EOR has the built-in profit incentive from the sale of incremental oil. Perhaps the incentives for deep saline formations could offset this built-in advantage.

However, I suggest that the best deep saline formations for sequestration are those that lie beneath oil and gas fields. The reasons for this are many:

(1) Areas with oil and gas fields tend to have more data associated with them, driven by previous or ongoing oil and gas exploration, whereas areas not prone to oil gas have sparse, if any, data. Data enable us to better characterize the area, which gives us greater certainty that the CO2 will stay where it was injected.

(2) Oil and gas fields tend to have infrastructure to transport and inject CO_2 locally, including pipelines or at least existing pipeline rights-of-way.

(3) Oil or gas reservoirs, especially active ones, may be monitored for CO_2 that may leak from the target saline formation below. Because of its low density, CO_2 will always migrate vertically towards the surface, and in this scenario will reach the oil/gas reservoir first. Tracers, if needed, may be injected with the CO_2 to provide a means of detecting the CO_2 if it moves into the oil/gas reservoir. This effectively provides an early-warning system that the CO2 is not staying in the targeted reservoir.

Thus, perhaps the greatest incentives could be instigated for deep saline reservoirs beneath oil/gas fields. In sum, I recommend that incentives be provided to stimulate sequestration operations, prioritized according to the high-to-low order below:

(1) deep saline formations underlying oil/gas fields, to use available relevant data to characterize the target formation and provide monitoring opportunities. Additionally, negotiating mineral rights, water rights, and "pore ownership" associated with

sequestration will likely be easier in formations within and under oil/gas fields, because such rights in these areas were previously evaluated, in general.

(2) deep saline formations not underlying oil/gas fields

(3) oil and gas reservoirs with maximized sequestration and minimized CO_2 recycling (i.e., minimize use of re-produced CO_2 for continued EOR).

2. Potential Barriers and Restrictions for Geologic CO_2 Sequestration

The Pipeline Differential

Adoption of sequestration requires not just good geology, but also pipelines. Pipelines are necessary to transport the vast amounts of CO_2 to be sequestered. A typical coal-fired power plant produces 1 to 15 million tons of CO_2 per year, and the ideal sequestration reservoir may be tens to hundreds of miles away. The southwestern U.S. enjoys a limited CO_2 pipeline network for transporting CO_2 from natural CO_2 reservoirs in southern Colorado and New Mexico into the Permian Basin of western Texas for EOR. The presence of this existing pipeline infrastructure is facilitating numerous medium- to large-scale sequestration pilot demonstrations, and is also providing a basis for planning future commercial sequestration operations by several major electric utilities in the region. For example, discussion focuses on using these major pipelines for linking CO2 sources (power plants) with the best CO2 storage sites.

However, in other parts of the country, planning for commercial sequestration is hampered because of the lack of such pipeline infrastructure. Commercial operations will likely go forward in these areas – the geology is good for carbon sequestration – but pipeline costs currently exceed \$20,000 to \$50,000 per mile, severely limiting their expansion.

In sum, providing incentives for areas without existing pipelines could help stimulate the infrastructure development necessary for long-term commercial sequestration possibilities. If large-scale commercial CO_2 sequestration is to become a reality, regional and/or national CO_2 pipelines that mimic the natural gas pipeline infrastructure will be needed.

Liability for sequestered CO_2

Liability of CO_2 capture and geological sequestration is generally classified into (a) operational liability and (b) post-injection liability. For both types of liability, I recommend that ownership and liability should be one and the same, i.e., whatever entity takes ownership also takes liability.

If a State takes on liability, then that state could own the CO_2; likewise for a private company. In many states, especially oil-producing states, CO_2 is a commodity, and therefore most liability-holders will probably want to own the CO_2. In some states, CO_2 may not be as valuable a commodity, and in this case private or state/federally sponsored insurance may be preferred.

Regardless of whether liability protection is provided by state, federal, or private entities, the scale of liability costs will be determined by the amount of data available to characterize a sequestration site's capability to retain CO_2 and to evaluate and provide quantified risk assessments. The more data that are available and useable, the lower the likely liability cost. Liability characterization frameworks are being developed by the U.S. Department of Energy's Regional Partnerships, and this work is being done in collaboration with federal agencies, including the U.S. Geological Survey.

In order to maximize participation in this process, I recommend that private companies be encouraged to provide their oil/gas or other subsurface geological information to the federally sponsored NATCARB databases. These data are necessary to determine the liability protection necessary for different sequestration sites.

I also recommend federal involvement in developing protocols that provide indemnification at a State or federal level for the ultimate fate of the sequestered CO2. Such a program could be instigated with a formal classification of liability "level," the value of which to be determined by the data available to characterize a site and its risks. As mentioned previously, the U.S. Department of Energy's Regional Partnerships are collaborating with the U.S. Geological Survey and other entities to draft such a classification system.

Capacity and Risk Assessments

As mentioned above with respect to liability, comprehensive fundamental geological data are required to evaluate risk and ultimate levels of liability protection requirements. These data are also necessary for accurate estimates of reservoir CO_2 capacities throughout the U.S. The U.S. Department of Energy's Regional Partnerships finished an initial assessment of subsurface and surface (terrestrial/vegetation/soil) storage capacity, and will continue updating this assessment annually for the coming decade. More data are being collected every week, populating a national database of geologic sequestration data, also known as "NATCARB." Local, regional and national capacities are continually being updated, and this work is carried out in collaboration with the U.S. Geological Survey and a collective of individual State Geological Surveys. The Regional Partnerships and the U.S. Geological Survey are working together at this time to identify how the U.S.G.S. can best complement the ongoing Partnerships program.

Regulatory Uncertainty

At this time, the regulatory frameworks for carbon capture and sequestration are still evolving. The final regulatory regimal will greatly affect the ultimate success of commercial-scale carbon sequestration. I list below many rules/regulation topics that possess some uncertainty, and provide some suggestions for these:

1. Agency regulatory authority: I recommend that individual states assign sequestration regulatory efforts to current oil/gas regulatory agencies at the state level. The State oil and gas agencies in many States are currently administering CO2 injection for EOR through the EPA's Underground Injection Classification program.
2. Ownership of pore-space and rights to sequester: I recommend that individual states implement pore-space/rights ownership to be similar to existing oil/gas frameworks (e.g., as an example or template or model). Negotiating pore-space ownership and rights to sequester will likely be easier in formations within and under oil/gas fields, because such rights in these areas were previously evaluated, in general.
3. Mineral and water rights: I recommend that individual states implement pore-space/rights ownership to mimic existing oil/gas frameworks (e.g., as an example or template or model). Negotiating mineral and water rights associated with sequestration will likely be easier in formations within and under oil/gas fields, because such rights in these areas were previously evaluated, in general.
4. Radius of influence and regulation of injection volumes: I recommend that individual states make radius of influence to be similar to existing oil/gas frameworks (e.g., as an example or template or model).

5. Need for unitization or eminent domain: I recommend that individual states make unitization/eminent domain to be similar to existing oil/gas frameworks (e.g., as an example or template or model).
6. Mechanical integrity of injection wells and legacy wells penetrating sequestration reservoir: I recommend that legacy wells and mechanical integrity be regulated strictly (more strictly than oil/gas wells), because of the liability and risk associated with well breakdowns or failures.
7. Well injection pressure limitations: I recommend that pressure limitations be at most 80% of least principal stress (also known as the "fracture pressure" or "fracture gradient").
8. CO2 Purity limitations and testing: I recommend 90% CO2 purity, minimum.
9. Enhanced oil recovery and sequestration: I recommend individual states encourage EOR and optimized/maximized sequestration, as outlined previously in this document.
10. Injection monitoring and reporting: I recommend rigorous monitoring and reporting standards, again because of liability and risk. The U.S. Department of Energy and its sponsored projects are developing guidelines and standards for monitoring and reporting.
11. Bonding: I recommend that individual states make bonding aspects to be similar to existing oil/gas frameworks (e.g., as an example or template or model).
12. Permitting: EPA has regulatory control, but should preferably delegate implementation to individual states agencies that already regulate oil/gas production and produced water disposal.
13. Closure (post-injection) monitoring and reporting: I recommend rigorous/strict closure monitoring and reporting (again, to account for liability and risk). The U.S. Department of Energy and its sponsored projects are developing guidelines and standards for minimum closure monitoring and reporting.
14. Surface owners rights: I recommend that individual states make surface rights for sequestration to be similar to existing oil/gas frameworks (e.g., as an example or template or model).

3. Brief Primer on Carbon Sequestration Concept

At the moment, 25 field geologic sequestration demonstration tests are being designed and scheduled for deployment in the U.S. over the coming 3 years. An additional 20 or so are ongoing or slated for deployment soon in other countries. Most of these tests are using different technologies, including different engineering designs, different monitoring approaches, different risk assessment protocols and different mitigation strategies. And, most of these tests are relatively small in scale: small injection rates compared to typical power plant emissions output. The uncertainties (error) associated with evaluation and design of large-scale sequestration operations are significant. For large-scale geologic sequestration to be deployed and sustainable over the long-term, a realistic (field-based) evaluation of uncertainties, and how these uncertainties affect risk assessment and mitigation strategies, must be carried out. Additionally, the community also needs a meaningful assessment of CO_2 trapping mechanisms and the physical and chemical factors that may cause the mechanisms to lose efficacy under realistic (field) conditions.

The purpose of this brief primer section is to summarize CO_2 sequestration concepts, from the macro-scale general operation to micro-scale trapping mechanisms.

Macro-Scale: Geological CO_2 Sequestration

The general premise of geological CO_2 sequestration is to

(5) separate CO_2 from power plant flue gases,
(6) capture that CO_2 in a separate stream,
(7) compress the CO_2 to elevated pressures to maximize its density,
(8) inject the CO_2 into subsurface geological formations ranging from 2,500 to 20,000 feet depth.

Target storage reservoirs are porous and permeable rock layers, overlain by low-permeability confining layers (Figure 1). Such geologic reservoirs have contained brine, oil and natural gas for millennia, and thus using these reservoirs for storing CO_2 is a very viable concept. Target reservoirs are commonly classified by what type of fluid they hold, including:

- *Depleted oil and gas fields:* Injection of CO_2 into these reservoirs can enhance oil recovery (EOR) or gas recovery (EGR);
- *Deep unmineable coal seams*: Injection of CO_2 into these reservoirs can enhance gas recovery (EGR);
- *Deep saline formations*: classified as reservoirs with brine salinities greater than 10,000 ppm; injection into these reservoirs is preferred by many because the brine is not useable for other purposes.

With a robust confining layer (Figure 1), sequestration duration can be maximized and risk minimized. With respect to engineering, such CO_2 injection has been done for decades in many areas of the U.S., for enhanced oil recovery. Thus, the engineering and technological details are relatively mature.

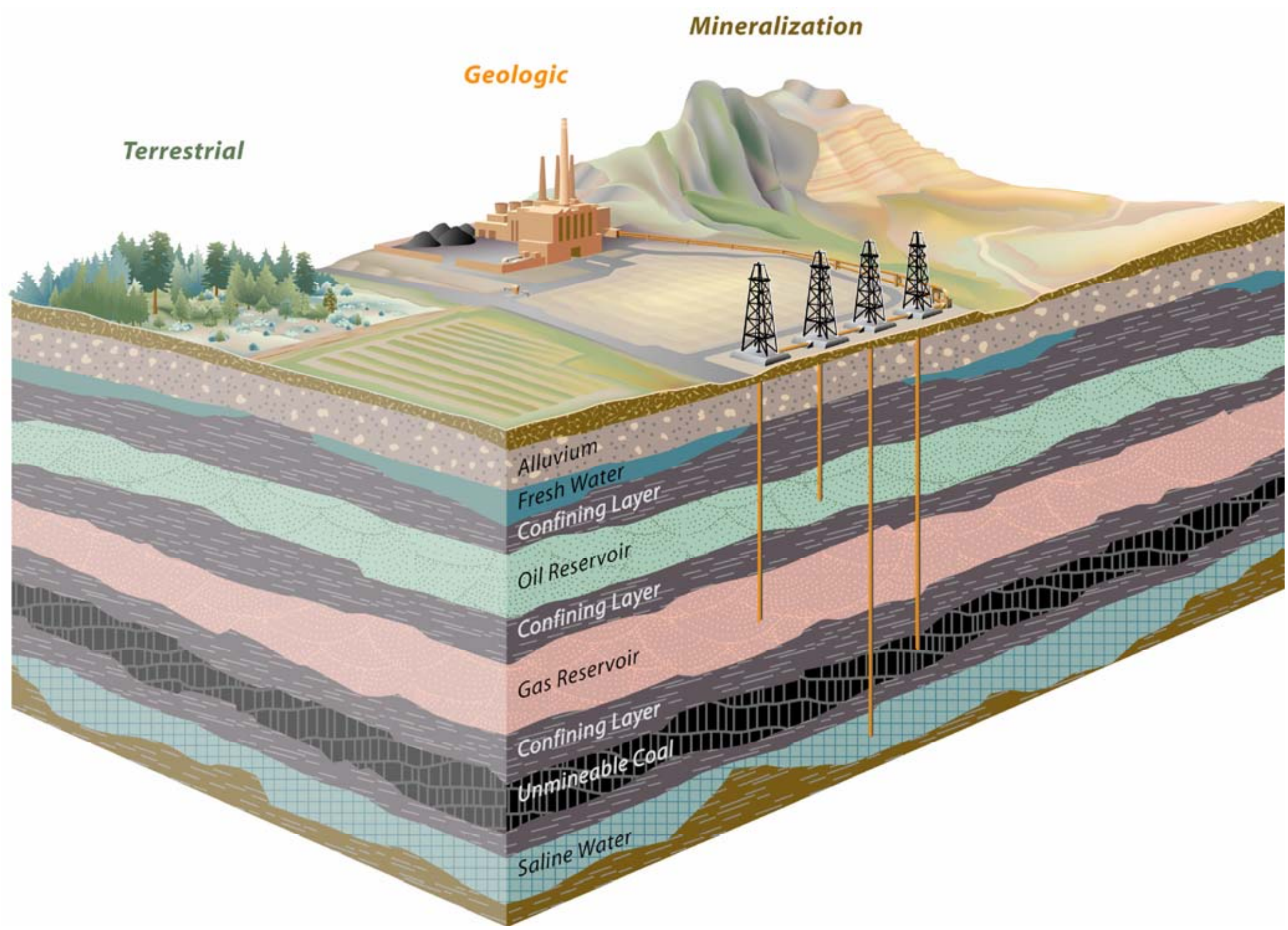
Micro-Scale: CO_2 Trapping Mechanisms

In this primer I describe the four primary geologic trapping mechanisms, including hydrostratigraphic, residual gas, solubility, and mineral trapping. Potential failure modes of each trapping mechanism are outlined, including discussion of how to define uncertainty of these failure modes.

Hydrostratigraphic Trapping

Hydrostratigraphic trapping refers to trapping of CO_2 by low permeability confining layers (Figure 1). This type of trapping is often distinguished by whether the CO_2 is contained by stratigraphic and structural traps, e.g., similar to oil and gas reservoirs, called static accumulations, or whether it is trapped as a migrating plume in large-scale flow systems, called hydrodynamic trapping. In general, CO_2 is trapped in permeable rock units in which the fluid flow is constrained by upper and lower less-permeable "barrier" lithologies. Such top and bottom seals are often formed by shale or salt units; lateral flow barriers may be due to facies changes or to faults. Faults and fractures may affect fluid flow; in some cases faults/fractures may be sites for preferential fluid flow, whereas in other cases they may inhibit fluid flow. Deep saline units typically have large lateral extents, while oil and gas reservoirs are typically much smaller. Although reservoirs may be classified by the nature of trapping mechanism, the geologic community tends to distinguish them on the basis of rock type.

Figure 1. Sequestration options: (1) terrestrial sequestration, including changes in land-use and tillage practices that increase carbon-uptake by soils and vegetation, (2) geologic sequestration, including injection and storage in deep saline formations, oil/gas reservoirs, and coalbeds, with a confining layer above to keep CO_2 in place, and (3) mineralization, which involves converting CO_2 to mineral precipitates, such as limestone. Geologic sequestration is the most economic, as it provides the greatest capacity for its cost. Terrestrial provides relatively low capacity, while mineralization is prohibitively expensive at this time. Figure provided by the Southwest Regional Partnership on Carbon Sequestration (and drafted by the Colorado Geological Survey).



Residual Gas Trapping

At the interface between two different liquid phases (such as CO_2 and water), the cohesive forces acting on the molecules in either phase are unbalanced. This imbalance exerts tension on the interface, causing the interface to contract to as small an area as possible. The importance of this interfacial tension in multiphase flow is paramount; the multiphase CO_2-brine-oil-gas flow equations are more sensitive to interfacial tension than many other fluid properties. Interfacial tension may trap CO_2 in pores, if fluid saturations are low. The threshold at which this occurs is called the "irreducible saturation" of CO_2, and is a key concept for defining "residual gas trapping." The magnitude of residual CO_2 saturation within rock, and thus the amount of CO_2 that can be trapped by this mechanism, is a function of the rock's pore network geometry as well as fluid properties. Geologic conditions that impact the amount of CO_2 trapped as a residual phase include petrophysics, burial effects, temperature and pressure gradients, CO_2 properties (density) under different P-T conditions, and on engineering parameters such as injection pressure, induced flow rates, and/or well orientation.

I view residual gas trapping as a secondary mode of sequestration relative to hydrostratigraphic trapping. Under this assumption, CO_2 would be injected for the purpose of hydrostratigraphic trapping, and residual gas trapping would be an additional process that renders the CO_2 immobile within hydrostratigraphic traps. Such an assumption has implications for evaluating possible failure modes and associated mitigation plans.

Solubility Trapping

Perhaps the most fundamental type of trapping is dissolution, or "solubility trapping." First, CO_2 dissolves to an aqueous species:

$$CO_2\ (g) + H_2O = H_2CO_3, \tag{1}$$

(relatively slow rates)

followed by rapid dissociation of carbonic acid producing bicarbonate and carbonate ions while lowering pH, or

$$H_2CO_3 = H^+ + HCO_3^- \tag{2a}$$

(relatively fast rate)

$$HCO_3^- = H^+ + CO_3^{--}. \tag{2b}$$

(relatively fast rate)

This leads to a series of additional reactions and "mineral trapping," discussed in the next section. The amount of sequestration possible through solubility trapping is very limited per unit mass of water, as groundwater (brine) can only dissolve up to a few mol% or less, depending on pressure (P), temperature (T), and salinity. Over large volumes of reservoir, solubility trapping may provide a significant amount of storage.

Mineral Trapping

"Mineral trapping" refers to the process of CO_2 reacting with divalent cations to form mineral precipitates in the subsurface. The reactions, especially reaction rates and associated processes that affect rates (e.g., complexation, pH buffering, etc.) are complicated and make estimates of CO_2 storage capacity difficult. However, mineral trapping is assumed to be a relatively safe mechanism that may sequester CO_2 for millions of years.

While mineral trapping may not be permanent, it can certainly render CO_2 immobile for very long time scales. The main source of uncertainty associated with mineral trapping are associated with the kinetic rate coefficients and reaction specific surface areas of minerals for the many homogeneous and heterogeneous reactions.

Potential Failure Modes

Hydrostratigraphic Trapping Failure Modes

All CO_2 trapping mechanisms have several failure modes. Critical objectives are to ascertain the physical and chemical processes of each failure mode and to minimize uncertainties in the characterization, and potential range of response, of those processes under sequestration conditions. Major failure modes for hydrostratigraphic trapping include:

(1) unintended migration by pre-existing but unidentified faults, fractures, or other fast-flow paths (e.g., Figure 1),
(2) unintended migration by stress-induced or reactivated fractures or faults,
(3) unintended migration by reaction-induced breaching of a seal layer
(4) unintended lateral flow to unintended areas,
(5) catastrophic events (e.g., unexpected earthquakes, etc.),
(6) wellbore failure events.

One approach to mitigating several of these failure modes is to select a storage site with multiple alternating seals and reservoirs above the primary (intended) reservoir, sometimes described as stacked reservoirs. However, even when stacked reservoirs are present, other measures must be taken to minimize risk of failure.

I view hydrostratigraphic trapping as the primary mechanism of CO_2 storage in subsurface geologic reservoirs. I suggest that the other trapping mechanisms, including residual gas trapping, solubility trapping, and mineral trapping, are specific modes of CO_2 storage within hydrostratigraphic traps. As such, the failure mechanisms for hydrostratigraphic trapping are of primary importance. I suggest that risk mitigation programs should make quantification of probabilities for hydrostratigraphic trapping failure modes a priority. However, under conditions of a failed hydrostratigraphic trap, I presume that leakage from an intended reservoir may lead to CO_2 movement into secondary hydrostratigraphic traps above the target reservoir/seal (e.g., stacked reservoirs), for example; in this case, residual gas trapping, solubility trapping, and mineral trapping all become mechanisms for helping to keep the CO_2 in place in the secondary reservoir. Additionally, if secondary reservoirs have no seal or hydrostratigraphic trap (in a strict sense), these other trapping mechanisms may provide an important overall damping of the flux of CO_2 back to the surface. Thus, although hydrostratigraphic trapping is priority, the other trapping mechanisms are still very important and uncertainty associated with each must be addressed.

Residual Gas Trapping Failure Modes

The primary failure mode for residual gas trapping is loss of capillary forces (surface tension) of the pore matrix. Such loss would be due to any process that changes the pore geometry or size or changes the interfacial tension, including compaction, dissolution or precipitation of cements in or around pores, or changing fluid composition. All of these processes require relatively long periods of time, and thus I suggest that risk is low for any of these to occur within timeframes of interest. Additionally, if these processes do occur, the most likely effect will be for CO_2 to dissolve into surrounding brine or to transition to free phase CO_2. At that point, the CO_2 is subject to the same set of trapping mechanisms for hydrostratigraphic trapping (recall that I assume the primary goal is hydrostratigraphic trapping, with residual gas trapping as a means of rendering CO_2 immobile within hydrostratigraphic traps).

Significant (large) changes in fluid pressure or temperature throughout the rock unit may change the fluid properties enough to reduce surface tension as well, although this is less likely to occur (low risk), or at the least is easier to monitor.

Solubility Trapping Failure Modes

The primary failure mode for solubility trapping is exsolution, which would only occur under significant (large) changes in pressure or temperature. As suggested above, the risk of major changes in pressure or temperature in a deep reservoir is very low, and monitoring for such changes over time is straightforward. Much like with residual gas trapping, I assume that the primary intended storage mechanism for geologic sequestration will be hydrostratigraphic trapping, with solubility trapping as one mode of storage within hydrostratigraphic traps. Following failure of solubility trapping, the CO_2 is still subject to the failure modes discussed under hydrostratigraphic trapping.

Mineral Trapping Failure Modes

The primary failure mode for mineral trapping is dissolution of the carbonate minerals that trapped CO_2. This is always a possibility, but much like for exsolution, this would take a great amount of time, and the surrounding brine would need to provide conditions that promote dissolution (e.g., low pH plus undersaturated with respect to bicarbonate for carbonate reactions). By monitoring the P-T and fluid composition through time, the status of mineral trapping and failure (dissolution and release of CO_2) can be easily monitored.

Much like with solubility trapping and residual gas trapping, I assume that the primary intended storage mechanism for geologic sequestration will be hydrostratigraphic trapping. Mineral trapping is therefore viewed as a means of rendering CO_2 immobile within hydrostratigraphic traps. Following failure of mineral trapping (dissolution and release of CO_2), the CO_2 is still subject to the failure modes discussed for hydrostratigraphic trapping.

Approach for Quantifying Uncertainty of Trapping Mechanisms and Failure Modes

I suggest an approach that includes three key components: (1) comprehensive integration of previous and ongoing basic research, (2) comprehensive assessment of previous and ongoing field demonstrations, and (3) a program of new laboratory and large-scale field testing. All three components are important for identifying gaps in the current state-of-the-art, for defining and calibrating appropriate phenomenological models, and for quantifying uncertainty of trapping failure modes. The U.S. Department of Energy through its Regional Partnerships program is carrying out several commercial-scale (1 million tons/year, the scale of a typical power plant's emissions) sequestration deployment demonstrations in the coming decade, with two or three of these to begin in 2008.

Quantitative assessment of geologic uncertainty is critical to success of sequestration. In the oil industry, several different approaches have been used to obtain probability distribution functions (PDFs) of desired parameters, such as hydrocarbons in place, recovery factors, etc. In CO_2 sequestration the community will employ such approaches for many facets of sequestration, for example, determiniation of critical fault properties that could lead to hydrostratigraphic trapping failure or to thickness variations of the seal that could lead to seal breach. High resolution data are needed for this effort.