**California Carbon Capture and Storage Review Panel**

**TECHNICAL ADVISORY COMMITTEE REPORT**

# Monitoring, Verification, and Reporting Overview

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# CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

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***Other white papers for the panel will include***
Review of Saline Formation Storage Potential in California

Options for Permitting Carbon Capture and Sequestration Projects in California

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Sequestration Risk History

## Introduction

In the context of geologic $CO_2$ storage (GCS), Monitoring, Verification, and Reporting (MVR)[1] refers to activities for collecting and reporting data about the characteristics and performance of GCS projects. For setting state regulatory policy, the primary purposes of MRV will be to verify that projects perform as expected—that ecosystems, local populations, livestock, and natural resources such as groundwater and recoverable oil and gas are protected, that damages from seismicity do not result from injecting $CO_2$, and that the proposed reduction in $CO_2$ emissions is achieved. This paper focuses on monitoring for leakage from the subsurface as paramount to protecting people, resources, and the environment, as well as for assuring emissions reductions. Even though monitoring of surface facilities is important, focus is on the subsurface where the technical issues are less well defined. The paper summarizes available measurement techniques for detection of leakage and the overarching approaches for combining these techniques into a monitoring program. Because of public sensitivity to earthquakes in California, a separate section is provided to discuss induced seismicity monitoring.

## Overview

The major components to be addressed by monitoring in GCS projects include: (1) injection rates and pressure, (2) injection well integrity, (3) subsurface distribution of the $CO_2$, and (4) the local environment.[2] For on-shore geological storage reservoirs, monitoring can take place in the storage reservoir itself or in shallower formations, in the vadose zone, in terrestrial ecosystems, and in the atmosphere. Offshore monitoring of storage projects will address the same components for the subsurface, but will need to take into account potential dissolution into seawater, transport with the water column, and sea-air interface.

Many of the measurement technologies for monitoring GCS are drawn from other applications such as the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, safety procedures for industries handling $CO_2$, and ecosystem research.[3,4] These established practices provide numerous measurement approaches and options—a monitoring toolbox—which enables development of tailored,

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[1] The term monitoring, verification, and accounting (MVA) is also commonly used.

[2] *IPCC Special Report on Carbon Dioxide Capture and Storage,* published for the Intergovernmental Panel on Climate Change, Cambridge University Press, New York, NY, 2005.

[3] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations.

[4] Benson, S.M., J. Apps, R. Hepple, M. Lippmann, C.F. Tsang, and C. Lewis, 2002(b), Health, Safety, and Environmental Risk Assessment for Geologic Storage of Carbon Dioxide: Lessons Learned from Industrial and Natural Analogues, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

flexible monitoring programs for GCS. (A summary of specific measurement technologies is found in Appendix I.)

The value of a tailored approach to monitoring is threefold: first, optimum performance of many techniques depends on site-specific geologic attributes; second, the risks that need to be monitored will vary from site to site; and third, a tailored approach will enable the most cost-effective use of monitoring resources. From a regulatory perspective, a tailored approach will lead to regulations that are largely performance-based and non-prescriptive with regard to measurement methods. The downside of a tailored approach is that it will add considerable time and uncertainty (from the perspective of a project developer) to the regulatory process. The time required for an agency to review a tailored plan, and potentially coordinate reviews amongst several agencies, is much more than would be required for a prescriptive approach. In addition, regulatory staff will have to have a higher level of knowledge and expertise in the scientific underpinnings of a broad range of monitoring methods, as well as potential risks, in order to evaluate the efficacy of tailored approaches.

At a conceptual level, a tailored approach implies no distinction between saline formation MVR and MVR for enhanced oil recovery (EOR) combined with storage – in each case the program is developed according to the site-specific circumstances. Practically, there are important differences between EOR with storage and saline formation storage. Saline formation storage involves only injection of $CO_2$ while EOR involves production of $CO_2$ along with oil and other fluids, and separation and re-injection of $CO_2$, So, there are additional measurements and accounting steps associated with surface handling of $CO_2$ for EOR. Regarding the subsurface, the leakage risks for saline formation storage and EOR with storage will likely be different, leading to a different monitoring program. The risk of leakage arising from uncertainties in the geology of the site will be much less for an EOR project because of the knowledge about the subsurface obtained during development of the field for oil production. On the other hand, the risk of leakage from pre-existing wells will be higher for the EOR project.

Even if a tailored approach is followed, there are a minimum set of measurements associated with the injection well and injection operations, that would be appropriate. These include $CO_2$ detection sensors on the surface at the wellsite, pressure, temperature, and volume flow rate at the wellhead, downhole pressure and temperature at the injection interval, and mechanical integrity pressure testing of the casing and subsequent monitoring of annulus pressures. A performance-based approach that allows for a tailored measurement program with a minimum set of required measurements has been followed in developing the proposed EPA UIC Class VI regulations and the EPA proposed rule for mandatory reporting of greenhouse gases for injection and geologic storage. (A summary of these rules is found in Appendix II.)

## Baseline Data Collection and Subsurface Modeling

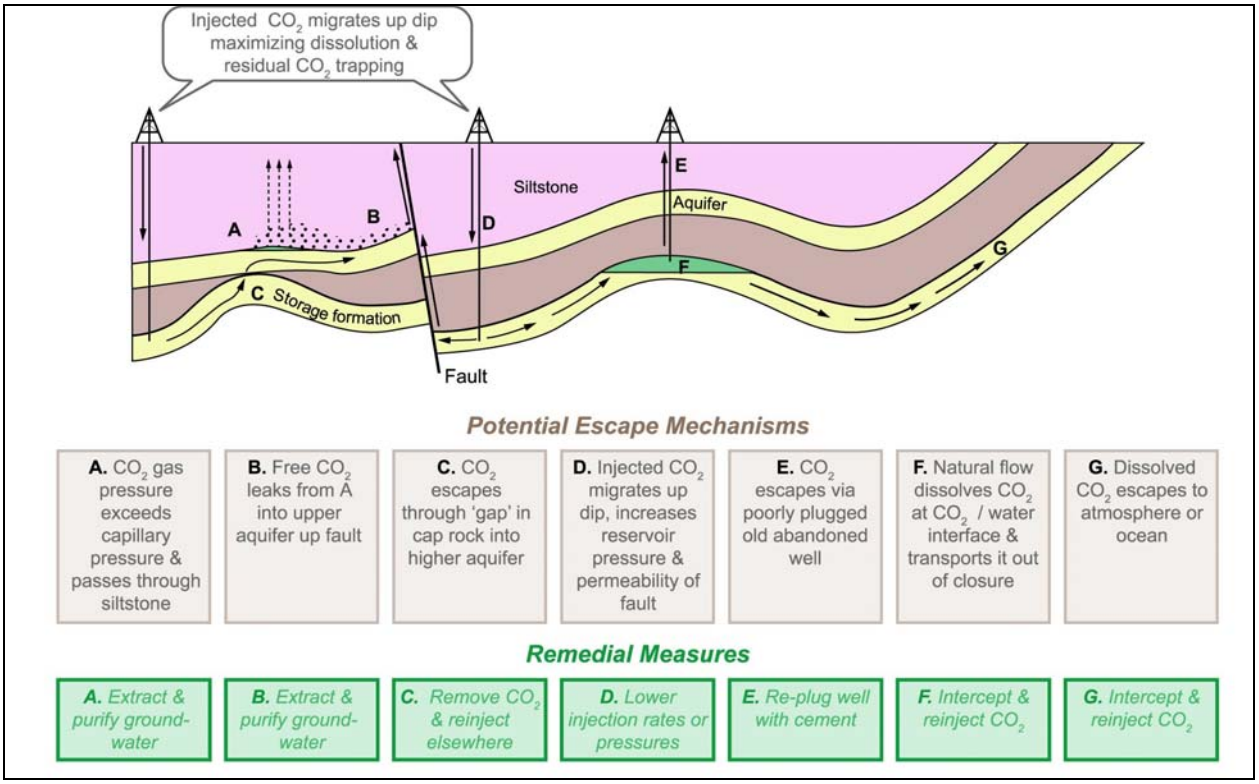
Establishing a baseline is an essential early step for successful monitoring of GCS. $CO_2$ is ubiquitous in the environment, both at the surface and in the subsurface, so it is important to establish initial levels before injection operations begin. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of $CO_2$; instead, it is the changes in these parameters over time that can be used to detect and track migration of $CO_2$ and its reaction products. For this reason, a well-defined baseline includes not only the average value of these parameters, but accounts for how they vary in space and over time before the project begins. Referred to as "time-lapse," this approach is the foundation for monitoring $CO_2$ storage projects. Without time-lapse measurements, it may not be possible to separate storage-related changes in the environment from the naturally occurring spatial and temporal variations as seen in the monitoring parameters. For most GCS projects, baseline data will be obtained during the pre-injection phase of the project. This is particularly important for storage projects in deep saline aquifers, for which there is less prior data than for depleted oil and gas fields.

Collection and analysis of monitoring data continues throughout the injection phase and into the post-injection and site closure phases. It is a dynamic and iterative process in which model predictions play a critical role. One of the key outputs of site characterization is a subsurface model. Comparisons of monitoring measurements with model predictions are made repeatedly to determine if the project is performing as expected, and what adjustments can be taken if it is not. Monitoring data is used to improve the initial subsurface model, which leads to increased confidence in subsequent model predictions. As knowledge and confidence in the performance of a project increase, monitoring may be scaled back, and the spatial and temporal frequency of monitoring measurements and types of measurement may be changed to reflect this increased understanding.

## Monitoring for leakage

Verification that a storage site does not leak is paramount to protecting people, resources, and the environment, as well as for assuring emissions reductions. Identification and assessment of potential leakage pathways during site characterization serves as a basis for developing appropriate operational standards, as well as monitoring and verification requirements that address site-specific conditions. The biggest risks of leakage for GCS overall arise primarily from existing and new wellbores and fractures and faults. Other possible pathways have also been identified, along with remedial actions, as illustrated in Figure 1.

**Figure 1 – Potential leakage routes and remediation techniques for $CO_2$ injected into saline formations[5]**




*Monitoring for wellbore leakage*

Wellbores that intersect the storage formation could provide pathways for $CO_2$ migration. Petroleum industry experience suggests that leakage from the injection well itself is one of the most significant risks for injection projects.[6] Pre-existing wellbores are considered to present a higher risk for leakage than new wellbores because of uncertainty about their condition. Locating nearby wellbores and assessing their leakage potential will be part of site characterization for many GCS projects.

Approaches for monitoring for wellbore leakage include:

- Pressure monitoring
  - In a closed well to establish that the casing is not leaking.
  - In overlying formations, where leakage of $CO_2$ will result in an increase in pressure in the water in the rock.

[5] IPCC Special Report, 2005.

[6] Ibid.

- Careful monitoring of temperature profiles along the well to identify temperature anomalies that indicate leakage.
- Geophysical wireline logs, used routinely in the petroleum industry, provide data on the integrity of the cement filling the space between the well casing and the rock. If $CO_2$ were to leak through the cement between the casing and the rock, it could enter rock formations above the injection interval. Geophysical wireline logs and can detect the presence of $CO_2$ in the rock within about a meter of the wellbore.
- Tracers can be injected behind the casing and their movement monitored to indicate the presence of leak paths at the casing-cement-rock interface.
- Water samples
  - Extracted from formations and analyzed for $CO_2$, or for tracers, if any have been injected with the $CO_2$.
  - Shallow groundwater samples obtained from existing water wells, or for-purpose drilled wells, and analyzed for $CO_2$ and or $CO_2$-water-rock reaction products.
- Sensors placed at ground surface in the vicinity of the well to measure $CO_2$ concentrations in the air.

*Monitoring for leakage from fractures and faults*

The second major category of potential leak paths is subsurface geologic structural features, of which fractures and faults are considered to represent the greatest risks. Fractures are essentially cracks in the rock, which could provide leak paths if they are present in the seals overlying the reservoir intervals. Faults are cracks where the two surfaces forming the crack have experienced relative movement, or slip. Faults can exist at any scale, and can therefore provide potential leak paths that extend from the storage reservoir to the surface. However, it should be noted that faults can also act as effective seals and traps for $CO_2$ storage.

Approaches to mapping the movement of $CO_2$ in the subsurface, which can also detect leakage out of the storage reservoir from fractures and faults, include:

- Geophysical monitoring methods: seismic, electromagnetic, and gravity
  - Seismic surveys produce images of subsurface properties by generating and recording induced sound waves as they travel through the earth. Although the size of a leak that can be detected using seismic surveys depends on many site-specific parameters, field experiments such as the Frio Brine Pilot tests in Texas and the Weyburn project in Canada suggest that seismic methods can detect leaks on the order of a couple thousand metric tons, a volume which is roughly equivalent to the size of a municipal swimming pool.
  - Gravity and electrical methods create lower-resolution images of the subsurface, and are less widely tested for $CO_2$ applications, but should provide additional

information on movement of the $CO_2$ plume. Gravity methods use the difference in density between $CO_2$ and water as a means of detection, whereas electrical methods use the difference in electrical conductivity between $CO_2$ and water, which is generally assumed to be saline for the purposes of $CO_2$ storage.

- Land-surface deformation, satellite, and airplane-based monitoring: injection of $CO_2$ into the reservoir causes increases in the pressure of the water in the rock, which extend far beyond the extent of the $CO_2$ plume. Recent work at the In Salah project in Algeria has demonstrated that small ground surface displacements, measurable from satellite-based systems, can be translated into images that show the migration of the $CO_2$, and would be able to show leakage via fractures and faults.
- Other approaches to monitoring for leakage due to fractures and faults require access to formations overlying the reservoir via wells. As discussed above, water samples, temperature and pressure measurement and geophysical wireline logs can be employed in such wells.

*Quantification of Leakage Measurements*

Consideration of potential reporting requirements needed to obtain credits for subsurface storage of $CO_2$ logically raises the issue of quantification of leakage. Many, if not most, of the measurement techniques discussed above for detection of a subsurface leak, also provide information which can be further analyzed to quantify the leak, though additional assumptions and data from other measurements may be needed. Site specific conditions, once again, will heavily influence the sensitivity and uncertainty in results. A handful of studies have been carried out to look at the sensitivity of pressure measurements and seismic measurements to the volume of a leak, and, as noted above, field studies to date suggest that under some circumstances, seismic methods can detect leaks of a few thousand tons of $CO_2$. In general, however, quantification of leakage is more challenging than leak detection and, and more experience and study is needed before definitive statements can be made about minimum detectable volumes.

## Monitoring Seismicity

Public awareness of, and sensitivity to, earthquakes, will likely result in special attention being paid to the part of the monitoring program focused on detecting any seismicity that might occur at a CCS site. The major concern is that $CO_2$ injection will cause earthquakes, where use of the term "earthquake" for most people outside of the scientific community, infers ground motion that people can feel and likely causes some harm. In fact, the number of natural seismic events that are not felt by the public far exceeds the number which are felt, and the same can be said for seismicity induced by subsurface operations. Nonetheless, there are a number of well documented cases to show that subsurface pressure increases, either from direct injection of fluids in the subsurface for waste disposal and geothermal energy development, or impoundment of large volumes of water at the surface in reservoirs, have caused seismicity that people can feel, and in some rare instances, caused harm. Even though, to date, there are no documented instances in which $CO_2$ injection has induced seismicity which has caused harm, appropriate design, operational and monitoring steps need to be taken to mitigate the possibility of any such events.

Monitoring for induced seismicity begins with establishing a record of the natural background seismicity in the region encompassing the project. This record is fairly good in many parts of California because an earthquake monitoring network is already in place. This network consists of seismometers located on the ground throughout the state and connected by satellite to a data collection facility. In most instances the existing network would need to be augmented by a local network designed specifically for the site, and consisting of seismometers located on the ground surface or in shallow boreholes. The local network would enable more accurate location of events and detection of smaller events than the regional network. The record of the natural background seismicity is important since it gives a baseline to determine if an event, which occurs after injection starts, is due to injection or natural tectonic processes.

After injection begins, it is important to analyze both the time history and the magnitude of any events that occur. Instrumentation for "real time" measurement and analysis, which is available, should be employed in order to facilitate immediate response to significant events. Definition of what constitutes a "significant" event, as well as actions which need to be taken in response to the event, should be part of the seismicity monitoring plan. Many factors affect the definition of a significant event. Geologic factors affect the magnitude of shaking and the potential for damage of structures, but sensitivity of the public to any seismicity that can be felt could also be a major factor. Induced seismicity is directly related to fluid pressure in the subsurface, so reduction of fluid pressures reduces seismicity. The potential for induced seismicity will decrease during the post-injection closure phase of a storage project due to the natural reduction of fluid pressures and it can be controlled during the operational phase by control of injection rates.

Since there is a cause and effect relationship between fluid pressures and seismicity, direct monitoring of subsurface fluid pressures should also be part of the induced seismicity monitoring program.

## Monitoring Costs

Monitoring costs will depend on many factors including plume size, regulatory requirements, duration of monitoring, geologic site conditions, and the particular methods selected for application. Because many of the technologies likely to be used are already in widespread use in the oil and gas industries, and the costs for these technologies are well constrained.

Despite this knowledge, there is limited real-world information available on costs for monitoring GCS projects. Benson and others estimated life-cycle monitoring costs for two scenarios: (1) storage in an oil field with EOR, and (2) storage in a saline formation.[7] The

[7] S.M. Benson, M. Hoversten, E. Gasperikova, and M. Haines (2005), Monitoring Protocols and Life-Cycle Costs for Geologic Storage of Carbon Dioxide, In, E.S. Rubin, D.W. Keith and C.F. Gilboy (Eds.),

scenarios were not developed to be prescriptive of what a monitoring program should be, but are representative of plausible examples. For each scenario, cost estimates were developed for a "basic" and an "enhanced" monitoring program. The basic monitoring program included periodic 3-D seismic surveys, microseismic measurements, wellhead pressure, and injection rate monitoring. The enhanced monitoring program added periodic well logging, surface $CO_2$ flux monitoring, and other advanced technologies. The assumed duration of monitoring included a 30-year injection period, as well as a post-injection monitoring period of 20 years for the EOR scenario and 50 years for the saline formation scenario. For the basic monitoring program, the undiscounted cost for both scenarios was \$0.16 – \$0.19/ton $CO_2$. For the enhanced program, the undiscounted cost was \$0.27 – \$0.30/ton $CO_2$.

Monitoring of off-shore sequestration projects will involve many of the same techniques used in on-shore projects, however, operation in the off-shore environment will influence costs. In general, acquisition of 3-D seismic data is less expensive off-shore than on-shore, particularly for large-scale surveys. Off-shore seismic surveys involve ship-towed systems while on-shore surveys involve wheeled vehicles and manual labor. Well-based measurements, however, are more expensive off-shore because of rig costs.

## Conclusion

Practical and cost-effective approaches to MVR will rely on a combination of measurements and model predictions, tailored to the geological attributes and risks of specific storage sites. Many current GCS projects involve research elements to further develop or adapt existing measurement tools to the characteristics of $CO_2$ storage or to test new techniques. This research aims to enhance our understanding of GCS, lower costs, gain lessons learned from field testing, and expand the options of an already robust monitoring toolbox.

The inherent variability in geologic environments call for flexibility in the MVR methods employed, the types and numbers of parameters measured, and the temporal and spatial frequency of their measurement. A consistent monitoring policy amongst regulatory entities will be essential to enable project developers to build unified, tailored monitoring programs that will allow GCS projects to move forward in a cost- and time-effective manner, while ensuring protection of the public, the environment, and natural resources.

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Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Vancouver, BC, Volume II, p. 1259-1265.

## Appendix I – Monitoring Measurement Methods

*$CO_2$ Flow Rates, Injection, and Formation Pressures*

Measurements of $CO_2$ injection rates are a common oil field practice, and instruments are available from commercial manufacturers. Typical systems use orifice meters or other differential producing devices that relate the pressure drop across the device to the flow rate. Recent enhancements in the basic technology are now available that allow for accurate measurements and injection control, even under varying pressure and temperature conditions.[8]

Measurements of injection pressure at both the wellhead and in the formation are also routine. A wide variety of pressure sensors, including piezo-electric transducers, strain gauges, diaphragms, and capacitance gauges are available and suitable for monitoring $CO_2$ injection pressures. Over the past two decades, fiber optic pressure and temperatures sensors have been developed, and many manufacturers now sell these products. Fiber optic cables are lowered into the wells and connected to the sensors to provide real-time formation pressure measurements. These new systems are expected to provide even more reliable measurements and well control.[9]

The current state of the art is more than adequate to meet the needs for monitoring $CO_2$ injection rates and wellhead and formation pressures. These will provide quantitative measures of the amount of $CO_2$ injected at a storage site for inventories, reporting, and verification and as input to modeling.

***Direct Measurement Methods for $CO_2$ Detection***

Direct measurements of $CO_2$ in air, water, or soils may be required as part of the monitoring program. For example, $CO_2$ concentrations in the air near the injection wells or abandoned wells may be monitored as a precaution to ensure worker and public safety at the storage site. In addition, nearby groundwater monitoring wells may be monitored periodically to ensure that the $CO_2$ storage project is not harming groundwater quality. If there is an indication that $CO_2$ has leaked from the primary storage reservoir and migrated to the surface, vadose zone and soil gas $CO_2$ concentrations may be monitored.[10]

Even when the storage project poses no safety or environmental concerns, direct measurement of $CO_2$ concentrations and $CO_2$ reaction products may assist in determining the extent of

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[8] Wright, G. and Majek, 1998, Chromatograph, RTU Monitoring of $CO_2$ Injection. Oil and Gas Journal, 20 July, 1998.

[9] Brown, G. A. and A. Hartog, November 2002, Optical Fiber Sensors in Upstream, Oil and Gas, Journal of Petroleum Technology.

[10] Strutt, M.H., S.E. Beaubien, J.C. Baubron, M. Brach, C. Cardellini, R. Granieri, D.G. Jones, S. Lombardi, L. Penner, F. Quattrocchi, and N. Voltattorni, 2002, Soil Gas as a Monitoring Tool of Deep Geological Sequestration of Carbon Dioxide: Preliminary Results from the Encana EOR Project in Weyburn, Saskatchewan (Canada), Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

solubility and mineral trapping. In addition, in some cases, it may be desirable to have a method to uniquely identify and trace the movement of injected $CO_2$ from one part of the storage structure to another.

*$CO_2$ Sensors for Measurement in Air*

Sensors for monitoring $CO_2$ continuously in air are used in a wide variety of applications, including $CO_2$ demand-controlled HVAC systems, greenhouses, combustion emissions measurement, and the monitoring of environments in which $CO_2$ is a significant hazard (such as breweries). Such devices, which rely on infrared detection principles, are referred to as infrared gas analyzers. Infrared gas analyzers used in occupational settings are small and portable. Most use nondispersive infrared or Fourier Transform infrared detectors. Both methods depend upon light attenuation by $CO_2$ at a specific wavelength, usually 4.26 μm. For extra assurance and validation of real-time monitoring data, federal regulatory agencies[11] use periodic gas sampling bags and gas chromatography for measuring $CO_2$ concentrations. Mass spectrometry is the most accurate method for measuring $CO_2$ concentration, but it is also the least portable. Electrochemical solid-state $CO_2$ detectors exist, but they are not cost-effective at this time.[12]

Common field applications in environmental science include the measurement of $CO_2$ concentrations in soil air, flux from soils, and ecosystem-scale carbon dynamics. Diffuse soil flux measurements are made using simple infrared analyzers.[13] For example, the U.S. Geological Survey measures $CO_2$ fluxes on Mammoth Mountain using these types of detectors,[14] and they have also been deployed at a carbon sequestration pilot study in Alabama.[15] Biogeochemists study ecosystem-scale carbon cycling using $CO_2$ detectors on towers that are 2- to 5-meters tall (eddy flux correlation measurements) in concert with wind and temperature data to reconstruct average $CO_2$ flux over large areas.

Remote sensing of $CO_2$ releases to the atmosphere is a more complicated method because of the long path length through the atmosphere over which measurements are made and because of the inherent variability of background atmospheric $CO_2$. The total amount of $CO_2$ integrated by a satellite through the depth of the entire atmosphere is large. Infrared detectors measure average $CO_2$ concentration over a given path length, so a diffuse or low-level leak viewed

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[11] For example, National Institute of Occupational Safety and Health, Occupational Safety and Health Act and the Environmental Protection Agency.

[12] Tanura, S., N. Imanaka, M. Kamikawa, and G. Adachi, 2001, A $CO_2$ Sensor Based on a Sc3+ Conducting Sc1/3Zr2(PO4)3 Solid Electrolyte, Sensors and Actuators B, 73, pp. 205-210.

[13] Oskarsson, N.K., Palsson, H. Olafsson, and T. Ferreira, 1999, Experimental Monitoring of Carbon Dioxide by Low Power IR-Sensors; Soil Degassing in the Furnas Volcanic Centre, Azores, J. Volcanol. Geotherm. Res, 92, pp. 181-193m.

[14] Sorey, M.L., C.D. Farrar, W.C. Evans, D.P. Hill, R.A. Bailey, J.W. Hendley II, and P.H. Stauffer, 1996, Invisible $CO_2$ Gas Killing Trees at Mammoth Mountain, California, U.S. Geological Survey Fact Sheet at http://pubs.usgs.gov/fs/fs172-96/. See also: http://volcanoes.usgs.gov/lvo/activity/monitoring/co2.php.

[15] http://www.licor.com/env/2010/pdf/soil_flux/secarb.pdf.

through the atmosphere by satellite would be undetectable. In contrast, $SO_2$ and integrated total atmospheric $CO_2$ are routinely measured.[16] Geologists use airborne instrumentation called COSPEC to measure the attenuation of solar ultraviolet light relative to an internal standard. $CO_2$ is measured either directly by a separate infrared detector, or calculated from $SO_2$ measurements and direct ground sampling of the $SO_2/CO_2$ ratio for a given volcano or event.[17] Remote-sensing techniques currently under investigation for $CO_2$ detection are LIDAR (light detection and range-finding), which is a scanning airborne laser, and DIAL (differential absorption LIDAR) that looks at reflections from multiple lasers at different frequencies.[18]

*Geochemical Methods and Tracers*

Geochemical methods are useful both for directly monitoring the movement of $CO_2$ in the subsurface and for understanding the reactions taking place between $CO_2$ and the reservoir fluids and minerals.[19] Fluid samples can be collected either directly from the formation using a downhole sampler or from the wellhead, if the well from which the sample is collected is pumped. Downhole samples are considerably more costly, but have the advantage that they are more representative of the formation fluids because they are not depressurized as they flow up the well. Methods for collecting downhole and wellhead fluids samples are well developed, and geochemical sampling is conducted on a routine basis.

Fluid samples can be analyzed for major ions (for example, Na, K, Ca, Mg, Mn, Cl, Si, $HCO_3^-$ and $SO_4^{2-}$) pH, alkalinity, stable isotopes (such as, $^{13}C$, $^{14}C$, $^{18}O$, $^{2}H$), and gases, including hydrocarbon gases, $CO_2$, and its associated isotopes.[20] Standard analytical methods are available to monitor all of these parameters, including the possibility of continuous real-time monitoring for some of the geochemical parameters.

Natural tracers (isotopes of C, O, H and noble gases associated with the injected $CO_2$) and introduced tracers (noble gases, $SF_6$, and perfluorocarbons) also may provide insight into the

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[16] Lopez-Puertas, M. and F.W. Taylor, 1989, Carbon Dioxide 4.3 Um Emission in the Earth's Atmosphere: a Comparison Between NIMBUS 7SAMS Measurements and Non-local Thermodynamic Equilibrium Radiative Transfer Calculations, J. Geophys. Res., 94(D10), pp. 13,045, 13,068.

[17] Hobbs et al. 1991, Mori and Notsu 1997, USGS 2001.

[18] Hobbs, P.V., L.F. Radke, J.H. Lyons, R.J. Ferek, and D.J. Coffman, 1991, Airborne Measurements of Particle and Gas emissions from the 1990 Volcanic Eruptions of Mount Redoubt, J. Geophys. Res., 96(D10), pp. 18,735-18,752.; Menzies, R.T., D.M. Tratt, M.P. Chiao, and C.R. Webster, 2001, Laser Absorption Spectrometer Concept for Globalscale Observations of Atmospheric Carbon Dioxide, 11th Coherent Laser Radar Conference, Malvern, United Kingdom.

[19] Gunter, W.D., R.J. Chalaturnyk, and J.D. Scott, 1998, Monitoring of Aquifer Disposal of $CO_2$: Experience from Underground Gas Storage and Enhanced Oil Recovery, Proceedings of GHGT-4, Interlaken, Switzerland, pp. 151-156; Gunter, W.D. and E. Perkins, 2001, Geochemical Monitoring of $CO_2$ Enhanced Oil Recovery. Proceedings of the NETL Workshop on Carbon Sequestration Science, http://www.netl.doe.gov/.

[20] Ibid.

underground movement of $CO_2$ and reactions between $CO_2$ and the geologic formation.[21] Tracers may also provide the opportunity to uniquely identify the source of $CO_2$. While it is comparatively straightforward to measure the parameters listed above, interpreting these measurements to infer information about geochemical reactions is more challenging. Only recently has significant attention been paid to understanding reactions between $CO_2$ and deep geologic formations shortly after $CO_2$ is introduced into the environment.[22]

### *Indirect Measurement Methods for $CO_2$ Plume Detection*

Indirect measurements for detecting $CO_2$ in the subsurface provide methods for tracking migration of the $CO_2$ plume in locations where there are no monitoring wells, or for providing higher resolution monitoring between wells or behind the cased portion of a well. Such indirect methods fall into four categories: well logs; geophysical monitoring methods such as seismic, electromagnetic, and gravity; land surface deformation using tiltmeters, plane, or satellite-based geo-spatial data; and satellite-based imaging technologies such as hyperspectral and infrared imaging.

The utility of these indirect methods is determined by (1) their threshold for detection of the presence of $CO_2$, (2) the extent to which the signal is uniquely related to the presence of $CO_2$ (for example, distinguishing between the effects of a pressure increase and the presence of $CO_2$), and (3) the degree of quantification that is possible (for example, the fraction of the pore volume occupied by $CO_2$).

To date, three-dimensional (3-D) seismic reflection surveys have been used to monitor, with excellent success, migration of the $CO_2$ plume injection at the Sleipner project in Norway, the Frio Brine pilots in Texas, the Nagaoka project in Japan, and the Weyburn project in Canada.[23] The success of this technology bodes well for the ability of indirect methods to track plume

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[21]Emberley, S., I. Hutcheon, M. Shevalier, K. Durocher, W.D. Gunter, and E.H. Perkins, 2002, Geochemical Monitoring of Fluid-Rock Interaction and $CO_2$ Storage at the Weyburn $CO_2$-Injection Enhance Oil Recovery Site, Saskatchewan, Canada, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002; Blencoe, J.G., D.R. Cole, J. Horita, and G. Moline, 2001, Experimental Geochemical Studies Relevant to Carbon Sequestration, Proceedings of the First National Symposium on Carbon Sequestration, U. S. National Energy Technology Laboratory, Washington DC; Kennedy, B.M. and T. Torgersen 2001, Multiple Atmospheric Noble Gas Components in Hydrocarbon Reservoirs: A Study on the Northwest Shelf, Delaware Basin, SE, New Mexico. Submitted to Geochimica Cosmochimica Acta, Also Lawrence Berkeley National Laboratory Report, LBNL-47383.

[22]Bachu, S. and W.D. Gunter, 1994, Aquifer Disposal of $CO_2$: Hydrodynamic and Mineral Trapping, Energy Conversion and Management, 35, pp. 269-279; Johnson, J.W., J.J. Nitao, C.I. Steefel, and K.G. Knauss, 2001, Reactive Transport Modeling of Geologic Sequestration in Saline Aquifers: the Influence of Intra Aquifer Shales and the Relative Effectiveness of Structural, Solubility, and Mineral Trapping During Prograde and Retrograde Sequestration, Proceedings of the First National Symposium on Carbon Sequestration, U. S. National Energy Technology Laboratory. Washington DC.

[23] Korbol, R., and Kaddour, A., 1995. Sleipner Vest $CO_2$ disposal – Injection of Removed $CO_2$ into the Utsira Formation. Energy Conversion and Management,36, 3-9, 509-512.

migration in the subsurface. However, 3-D seismic reflection surveys may not always be so successful; costs for these surveys are high compared to other available monitoring methods, and in some cases, the spatial resolution or the detection threshold may not be adequate. In addition, performing traditional 2- and 3-D seismic surveys in some settings may not always be feasible because of limitations on land access or use. Therefore, additional methods for plume detection are being evaluated, including innovate real-time seismic monitoring approaches.[24]

*Well Logs*

One of the most common methods for evaluating geologic formations is the use of well logs. Logs are run by lowering an instrument into the well and taking a profile of one or more physical properties along the length of the well. A wide variety of logs is available and can measure many parameters—from the condition of the well to the composition of pore fluids to the mineralogy of the formation. For geologic storage of $CO_2$, as is true for natural gas storage and disposal of industrial wastes in deep geologic formations, logs will be most useful for detecting the condition of the well and ensuring that the well itself does not provide a leakage pathway for $CO_2$ migration. Several logs are routinely used for this purpose, including temperature, noise, casing integrity, and radioactive tracer logs.[25] It is worth noting that the resolution of well logs may not be sufficient to detect very small rates of seepage through microcracks. The Resistivity (RST) log, which can be used to estimate the saturation of $CO_2$ in the pore space, has also been used with excellent success at the Frio Brine pilots in Texas.[26]

*Geophysical Monitoring Methods: Seismic, Electromagnetic, and Gravity*

It is natural to consider geophysical techniques for monitoring $CO_2$ migration because of the large body of experience in their application in the petroleum industry. Among geophysical techniques, seismic methods are by far the most highly developed. The most likely mode of application will be time-lapse, in which two surveys taken at different times would be used to evaluate the movement of $CO_2$. As mentioned above, this technique has been used very effectively for monitoring $CO_2$ movement at the Sleipner project, the Frio Brine pilots, the Weyburn project, and the Nagaoka project. Though time-lapse imaging is becoming more common, it is a much less mature technology than exploration geophysics.

The applicability of geophysical techniques depends, first, on the magnitude of the change in the measured geophysical property produced by $CO_2$, and second, on the inherent resolution of the technique. Finally, the applicability also depends on the configuration in which the measurement is deployed.

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[24] Daley, T., R.D. Solbau, J. B. Ajo-Franklin, S. M. Benson (2007) Continuous Active-Source Seismic Monitoring of $CO_2$ Injection in a Brine Aquifer, Geophysics, in press.

[25] Benson et al., 2002a, Op. cit.

[26] Hovorka, S.D., S. M. Benson, C. Doughty, B. M. Freifeld, S. Sakurai, T. M. Daley, Y. K. Kharaka, Mark H. Holtz, R. C. Trautz, H. S. Nance, L. R. Myer and K. G. Knauss. Measuring permanence of $CO_2$ storage in saline formations: the Frio experiment. Environmental Geosciences; June 2006; v. 13; no. 2; p. 105-121; DOI: 10.1306/eg.11210505011.

Gravity methods sense changes in density; electrical methods primarily respond to changes in resistivity; and seismic methods depend on both density and elastic stiffness. Gravity has been used to monitor $CO_2$ migration in off-shore environments at the Sleipner Project and was able to detect the injected $CO_2$. These physical properties are known for $CO_2$, typical reservoir fluids, and their mixtures, and so assessments can be made of expected changes in geophysical properties.[27] $CO_2$ is resistive, so electrical methods are candidates for brine bearing formations. For most of the depth interval of interest for sequestration, $CO_2$ is less dense and more compressible than brine or oil, so gravity and seismic methods are candidate methods for brine or oil bearing formations. At shallow depths, $CO_2$ has gas-like properties, so none of the geophysical methods are good candidates for monitoring $CO_2$ within a shallow, dry natural gas reservoir. Even in this case, however, since brine formations are commonly found above gas reservoirs, geophysical methods would still be candidates for detection of leaks. Research continues to refine the information available on the influence of varying $CO_2$ saturations on seismic and electrical properties.[28]

The area containing the $CO_2$ also must be of sufficient size to generate an interpretable geophysical signal. A relevant concept is resolution, which, in geophysics, is defined as the ability to distinguish separate features. For seismic methods, resolution is usually discussed in the context of reflection processing and expressed in terms of the size of the feature compared to the seismic wavelength. Numerous researchers have studied ways to improve seismic resolution.[29] Vertical resolution relates to bed thickness and the critical resolution thickness is about 1/8 wavelength. For thinner beds, separate reflections from the top and bottom cannot be identified. Lateral resolution is related to Fresnel zone size. When the lateral dimension is less than one Fresnel zone, reflected amplitudes are a function of size, in addition to property contrasts. Myer and others[30] studied the resolution of surface seismic for detecting subsurface volumes containing $CO_2$ and concluded that, at depth, a plume as small as 10,000 to 20,000 tons of $CO_2$ may be detectable, but would be difficult to resolve.

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[27] Batzle, M. and Z. Wang, 1992, Geophysics, 57, pp. 1396-1408 Magee, J.W. and J.A. Howley, 1994, Gas Processors Association, Tulsa, OK Research Report, RR-136; National Institute of Science and Technology (NIST), 1992, NIST Database 14 Mixture Property Database, version 9.08, U.S. Department of Commerce.

[28] Myer, L.R., 2001, Laboratory Measurement of Geophysical Properties for Monitoring $CO_2$ Sequestration, *Proceedings, First National Symposium on Carbon Sequestration*, U. S. National Energy Technology Laboratory, Washington DC.

[29] Widess, M., 1973, How Thin Is a Thin Bed?, *Geophysics*, 38(6), pp. 1176-1180; Sheriff, R., 1977, Limitations on Resolution of Seismic Reflections and Geologic Detail Derivable from Them, in Seismic Stratigraphy—Applications to Hydrocarbon Exploration, Memoir 21, G. Payton editor, *American Association of Petroleum Geologists*, pp. 3-14.

[30] Myer, L.R., G.M. Hoversten, and E. Gasperikova, 2002, Sensitivity and Cost of Monitoring Geologic Sequestration Using Geophysics, presented at the Sixth International Greenhouse Gas Technologies Conference (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

More recent work suggests that faults and fractures can be detected by seismic methods even though their thickness is much less than 1/8 wavelength.[31] Because the porosity of fractures, or a fault, is a small percentage of the total rock volume, the detectable volume of $CO_2$ would be much smaller than that cited above.

Seismic methods cover several frequency ranges. Surface seismic methods produce energy from 10 Hz to about 100 Hz. Crosswell seismic methods using rotary sources produce energy in the 100 Hz to 500 Hz range and, using piezoelectric sources, in the 1 to 2 KHz range. Borehole seismic methods produce energy in the 10 KHz range. Frequency is related to wavelength through velocity, so for typical sedimentary rocks, wavelengths of surface seismic methods are in the range of about 10 to 100 meters, suggesting that $CO_2$ plumes as thin as 2 to 15 meters may be detected. Wavelengths of high frequency borehole-deployed methods are much shorter, implying high resolution, but scattering and intrinsic attenuation limit the distance over which an interpretable signal will travel. High frequency borehole methods can penetrate only a few meters into typical sedimentary rock.

The resolution of potential field methods (essentially all geophysical methods other than seismic) is not formally defined. It is generally recognized that the resolution of these methods is much less than that of seismic.

Finally, all of the methods described above can be deployed in a number of ways, depending on the resolution and spatial coverage needed. For example, seismic data can be obtained in two or three dimensions where the seismic source and receiver are located at the ground surface. Alternatively, higher resolution data can be obtained from vertical seismic profiling where receivers are located along the length of a wellbore. Even higher resolution data can be obtained by locating the source and receivers in wellbores and imaging between them. Successful images of $CO_2$ migration during EOR have been obtained using cross-well seismic imaging. Similar configurations are applicable to electromagnetic techniques, including electromagnetic and electrical resistivity methods. Recent efforts are developing electrical resistance tomography, a simple approach that uses the wells themselves as electrodes, as a low-cost, low-resolution method for tracking $CO_2$ movement within a wellfield. A pilot test of this technology is underway at the Vacuum Field in New Mexico.[32]

One limitation of all these techniques is the difficulty in quantifying the amount of $CO_2$ that is present. For example, the presence of only a small amount of $CO_2$ creates large changes in the

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[31] Schoenberg, M., 1980, Elastic Wave Behavior across Linear Slip Interfaces, Journal of Acoustical Society of America, 68(5), pp. 1516-1521; Pyrak-Nolte, L., L.R. Myer, N. Cook, 1990, Transmission of Seismic Waves Across Single Fractures, Journal of Geophysical Research, 95(86), pp. 8617-8638.

[32] Newmark, R.L., A.L. Ramirez, and W.D. Daily, 2002, Monitoring Carbon Dioxide Sequestration Using Electrical Resistance Tomography (ERT): A Minimally Invasive Method, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

seismic velocity and compressibility of the rock.[33] However, as the pore space is filled with a larger fraction of $CO_2$, little additional change occurs. There is ongoing work to develop methods to quantify the saturation of $CO_2$ in the pore space by combining electrical and seismic imaging measurements.[34] While it is unlikely that monitoring the saturation of $CO_2$ will be needed as part of a routine monitoring program, having this capability may be useful for improving understanding of geologic $CO_2$ storage. Similar limitations may apply to quantifying the rate at which leakage is occurring using geophysical techniques alone.

*Land-Surface Deformation, Satellite, and Airplane-Based Monitoring*

Recent advances in satellite imaging provide new opportunities for using land surface deformation and spectral images to indirectly map migration of $CO_2$. Ground surface deformation can be measured by satellite and airborne interferometric synthetic aperture radar (InSAR) systems.[35] Tiltmeters placed on the ground surface can measure changes in tilt of a few nano-radians.[36] Taken separately or together, these measurements can be inverted to provide a low-resolution image of subsurface pressure changes. While these technologies are new for monitoring $CO_2$ storage projects, they have been used in a variety of other applications, including reservoir monitoring and groundwater investigations.[37] Satellite spectral imaging has been used to detect $CO_2$-induced tree kills from volcanic outgassing at Mammoth Mountain, California.[38] Maturation of these technologies may provide a useful and comparatively inexpensive method for monitoring migration of $CO_2$ in the subsurface and for ecosystem monitoring.

As indicated by the information in Table 1, there are a number of approaches and options for monitoring emissions from geological storage reservoirs. Today, the most practical and cost-

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33 Arts, R., O. Eiken, A. Chadwick, P. Zweigel, L. van der Meer, and B. Zinszner ,2002, Monitoring of $CO_2$ Injected at Sleipner Using Time Lapse Seismic Data, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

34 Hoversten, G.M., R. Gritto, T.M. Daley, E.L. Majer, and L.R. Myer, 2002, Crosswell Seismic and Electromagnetic Monitoring of $CO_2$ Sequestration, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

35 Zebker, H., 2000, Studying the Earth with Interferometric Radar, *Computing in Science and Engineering*, 2, No. 3, pp. 52-60, May-June, 2000.

36 Wright, C., E. Davis, W. Minner, J. Ward, L. Weijers,E. Schell, and S. Hunter, 1998, Surface Tiltmeter Fracture Mapping Reaches New Depths-10,000 Feet and Beyond?, *Society of Petroleum Engineering 39919*, April 1998.

37 Vasco, D.W., et al., 2001, Geodetic Imaging: High Resolution Monitoring Using Satellite Interferometry, *Geophysical Journal International*, 200, pp. 1-12; Hoffmann, J., H.A. Zebker, D.L. Galloway, and F. Amelung, June 2001, Seasonal Subsidence and Rebound in Las Vegas Valley, Nevada Observed by Synthetic Aperture Radar Interferometry, *Water Resources Research*, 37, No. 6, p. 1551.

38 Martini, B.A., E.A. Silver, D.C. Potts, and W.L. Pickles, 2000, Geological and Geobotanical Studies of Long Valley Caldera, CA, USA Utilizing New 5m Hyperspectral Imagery, Proceedings *of the IEEE International Geoscience and Remote Sensing Symposium*, July 2000.

effective approach would rely on a combination of measurements and model predictions to assess annual emissions from the geological storage reservoir. Since the same combination of measurements would not be appropriate for all storage sites, flexibility to tailor the monitoring to the specific geological attributes of the storage site would be beneficial.

**Table 1 – Monitoring Approaches**

| System Component | Monitoring Methods | Benefits | Drawbacks |
|---|---|---|---|
| Storage reservoir | Seismic<br>Gravity<br>Well logs<br>Fluid sampling | History match to calibrate and validate models<br>Early warning of migration from the storage reservoir | Mass balance difficult to monitor<br>Dissolved and mineralized $CO_2$ difficult to detect |
| Shallower saline formations below secondary seals | Seismic<br>Pressure<br>Gravity<br>Well logs<br>Fluid sampling | Good sensitivity to small secondary accumulations (~$10^3$ tonnes) and leakage rates<br>Early warning of leakage | Detection difficult if secondary accumulations do not occur<br>Dissolved and mineralized $CO_2$ difficult to detect |
| **Onshore** | | | |
| Groundwater aquifers | Seismic<br>Pressure<br>EM<br>Gravity<br>SP<br>Well logs<br>Fluid sampling | Sensitivity to small secondary accumulations (~$10^2$-$10^3$ tonnes) and leakage rates<br>More monitoring methods available<br>Detection of dissolved $CO_2$ less costly with shallow wells | Detection after significant migration has occurred<br>Detection after potential groundwater impacts have occurred |
| Vadose zone | Soil gas and vadose zone sampling | $CO_2$ accumulates in vadose zone making detection easier compared to atmospheric detection<br>Early detection in vadose zone could trigger remediation before large emissions occur | Significant effort for null result (e.g. no $CO_2$ from storage detected)<br>Detection only after some emissions are imminent<br>Does not provide quantitative information on emission rate |
| Terrestrial ecosystems | Vegetative stress | Vegetative stress can be readily observed using routine observation<br>Satellite and plane-based methods available for quick reconnaissance | Detection only after emissions have occurred<br>Vegetative stress can be caused by other factors<br>Land use change could alter the baseline<br>Does not provide quantitative information on emission rates<br>May not be useful in some ecosystems (e.g., deserts) |

| **System Component** | **Monitoring Methods** | **Benefits** | **Drawbacks** |
|---|---|---|---|
| Atmosphere | Eddy covariance<br>Flux accumulation chamber<br>Optical methods | Good for quantification of emissions | Distinguishing storage emissions from natural ecosystem and industrial sources necessitates comprehensive monitoring<br>May not be best suited for detecting anomalous emissions due to relatively small footprint compared to the size of the plume<br>Significant effort for null result |
| | | **Offshore** | |
| Water Column | Ship based fluid sampling and analysis<br>Autonomous vehicles with $CO_2$, pH and carbon cycle sensors | Direct measurement of water column and fluxes (using inverse models) | Distinguishing storage related fluxes from natural variability requires comprehensive monitoring<br>Quantifying separate phase $CO_2$ flux<br>Significant effort for null result |
| Atmosphere | Optical methods<br>Eddy covariance | Direct measurement of emission rate | Technology not well developed for this application<br>Quantification of emissions may be impractical<br>Changing emission footprint from ocean currents<br>Likely to be costly to maintain<br>Significant effort for null result |

## Appendix II – Summary of U.S. EPA Proposed Monitoring Rules

The U.S. EPA (EPA) has two separate but coordinated efforts related to monitoring of carbon capture and sequestration and enhanced oil recovery sites. The Office of Air and Radiation has issued proposed rules for reporting for carbon dioxide injection and geologic sequestration. The Office of Water has a proposed for a new class of wells (Class VI) for permitting injection of carbon dioxide under the Underground Injection Control (UIC) Program of the Safe Drinking Water Act. These two proposed rules serve different purposes. The monitoring plan under the reporting rule must be able to detect and quantify $CO_2$ any leakage from the subsurface to the surface. The monitoring plan for the UIC program Class VI wells must demonstrate protection of underground sources of drinking water. Other health and safety impacts are not directly addressed under either rule.

***Proposed rule for mandatory reporting of greenhouse gases for injection and geologic sequestration of carbon dioxide***

Subpart RR of the proposed mandatory reporting of greenhouse gases rule requires facilities that inject $CO_2$ for the purpose of geologic sequestration or enhanced oil recovery (EOR) to report basic information such as the quantity of $CO_2$ injected. Facilities that are claiming geologic sequestration will be subject to additional reporting and monitoring requirements including a mass balance estimation of $CO_2$ sequestered and an EPA approved monitoring, reporting, and verification (MRV) plan.[39] EOR facilities may opt into the more rigorous reporting requirements.

The proposed EPA-approved MRV plan is performance based, reflecting the commonly held belief that the most appropriate monitoring techniques should be selected based on site-specific geology and conditions. The EPA-approved MRV plan would include the following:

1. An assessment of risk of $CO_2$ leakage to the surface
2. A strategy for detecting and quantifying any $CO_2$ leakage to the surface
3. A strategy for establishing pre-injection environmental baselines
4. A summary of how the facility will calculate site-specific variables for the mass balance equation, calculating the amount of $CO_2$ sequestered

The monitoring plan must be found to be able to detect and quantify $CO_2$ leakage from the subsurface to the surface. The plan will need to prove that the chosen monitoring techniques are suitable for the type of leakage pathways and risks for each pathway.

The proposed regulation is for data collection and monitoring only and does not address impacts from leakage. The first point, assessment of risk, can be satisfied through a UIC Class VI permit, provided it includes surface monitoring and related environmental baseline components.

[39] EPA's usage is monitoring, reporting, and verification.

The overall performance standard for the monitoring plan is to detect and quantify $CO_2$ leakage from the subsurface to the surface. Each part listed above helps achieve the overall standard. The risk of leakage assessment must include "a combination of site characterization and realistic models that predict the movement of $CO_2$ over time and locations where emissions might occur." It must account for the appropriate spatial area, all potential leakage pathways, and include active and abandoned wells. A model overview including sensitivity and uncertainty analysis must be provided. The second part, a strategy for detecting and quantifying $CO_2$ leakage to the surface must include the methodology, rationale, and frequency of monitoring. Incorporation of unexpected leakage pathways, detection limits, monitoring locations, spatial array, and frequency of monitoring are all components. The plan must outline what measurements will occur if a leak is detected and should be conservative. For example, the facility must assume the duration of the leak to be equal to the time since the last monitoring event. The first part should serve as the basis for the strategy. The third part will set a baseline that will enable the detection and quantification of leakage. The final part will ensure that all above-ground emissions are not counted as stored. Overall, these four requirements ensure that all emissions will be detected and quantified.

Some monitoring is prescribed for both EOR and geologic sequestration sites. All $CO_2$ injection sites would be required to use flow meters to measure the volume of $CO_2$ during injection. These meters can be the same as those required under the UIC program.

***Proposed Rule Under the Underground Injection Control (UIC) Program for Carbon Dioxide ($CO_2$) Geologic Sequestration (GS) Wells***

The proposed UIC Rule for $CO_2$ GS Wells (Class VI) includes a combination of prescriptive and performance-based standards for monitoring. For example, the owner or operator must demonstrate internal and external mechanical integrity of the well. The internal integrity tests require use of continuous "monitoring of injection pressure, flow rate, and injected volumes as well as the annular pressure and fluid volume." The external mechanical integrity test can be done in a variety of ways, but must be one of the mentioned tests, or approved in the permitting process. However, plume and pressure front monitoring requirements are performance based with the operator required to show a monitoring plan to ensure that the injectate is safely confined in the intended subsurface geologic formations and underground sources of drinking water are not endangered. In addition, there are some requirements that pertain to all wells and some that are site-specific.

The monitoring plan "should be designed to detect changes in ground water quality and track the extent of the $CO_2$ plume and area of elevated pressure." The plan must also show that the site is "operating as intended and is not endangering USDWs."[40] The monitoring requirements cover the types of analysis that must be included (i.e., groundwater quality and geochemical changes above the confining zone), but do not specify the exact testing or location of monitoring. These should be "based on the identification and assessment of potential $CO_2$ leakage routes complemented by computational modeling of the site."

[40] Underground sources of drinking water.

Overall, the approach combines prescriptive standards with a performance-based standard that the monitoring plan must be able to demonstrate the ability to detect changes in groundwater quality and track the $CO_2$ plume and pressure front.